

DOCUMENT RESUME

ED 232 886

SE 042 784

TITLE Two Energy Futures: A National Choice for the 80s.
INSTITUTION American Petroleum Inst., Washington, D.C.
REPORT NO ISBN-0-89364-050-6
PUB DATE Jul 83
NOTE 233p.; For earlier edition see ED 196 683.
PUB TYPE Reports - General (140)

EDRS PRICE MF01/PC10 Plus Postage.
DESCRIPTORS *Coal; Depleted Resources; *Energy; *Energy Conservation; Environmental Education; *Federal Regulation; *Fuels; *Futures (of Society); Nuclear Energy; Petroleum Industry; Physical Environment; Policy Formation; Technological Advancement

IDENTIFIERS Alternative Energy Sources; Fossil Fuels; *Government Lands

ABSTRACT

In 1980, the American Petroleum Institute published the first edition of "Two Energy Futures." It described the U.S. energy experience of the 1970s and prospects for the 1980s, concluding that the nation could drastically reduce its dependence on uncertain sources of imported oil if the right choices were made by individuals and the government. This edition continues to examine the national energy picture: progress made and what remains to be done. Information is presented in 10 chapters. Introductory material, including discussions of energy developments during 1950s to 1980s and policy choices for the 1980s, is presented in the first chapter. Areas addressed in the remaining nine chapters include: oil and natural gas; coal; nuclear energy; synthetic fuels and renewable energy; energy conservation; energy and the environment; government lands (as a source of energy); economic benefits of reducing imports; and individual benefits of energy security. Footnotes for and sources of graphs presented in each chapter and bibliography are included in an appendix. Among the findings reported are those indicating that, despite considerable domestic energy progress and the adequacy of current world oil supplies, the long-term U.S. energy outlook remains unsettled and threatened by complacency. (JN)

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for the 80s

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American Petroleum Institute
2101 L Street, Northwest
Washington, DC 20037

Library of Congress Catalog Card Number: 83-72227
ISBN 0-89364-050-6

Portions of this book may be quoted, with citation of
the source.

Printed in the United States of America

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I. INTRODUCTION AND DOCUMENTATION

The 1970s were a period of worsening energy problems in the United States, with falling domestic production, rising domestic consumption and potentially disastrous growing dependence on insecure supplies of imported oil.

In 1979 we were importing nearly eight and one-half million barrels of oil a day -- nearly half of the oil Americans used.

The nation became appropriately concerned.

Then a dramatic turnaround began.

It came in part from a belated, broad recognition that we were in serious energy trouble, triggered chiefly by the supply shortages and gasoline lines that followed the sudden cutoff of Iranian exports. It came also, in part, from the news media's growing understanding of the problem and, in part, from special attention given energy by President Carter.

All of these factors helped bring about one essential change, initiated by President Carter and completed by President Reagan -- two presidents of vastly different political philosophies. That change was the decontrol of oil prices and the return to a market system for oil.

Oil decontrol marked the beginning of dramatic progress in the first years of the 1980s toward energy security. There was help also at that time from the gradual decontrol of some categories of natural gas.

Significant price-induced conservation resulted from investment in greater energy efficiency by energy consumers in all sectors of the economy.

The headlong decline in proved reserves of oil and natural gas, which account for almost three-fourths of U.S. energy consumption, was halted as record oil drilling took place and record capital expenditures were made for petroleum activities. After declining throughout most of the 1970s, oil production in the lower-48 states leveled off and began a slight increase. Meanwhile, new oil production began in Alaska.

Thus, the poor state of the nation's energy situation of the late 1970s improved dramatically and rapidly because of the decontrol of crude oil. The impetus arising from decontrol continues today and is essential to continued progress.

But even given the progress of the past few years, an assessment of the state of the nation's energy today must be mixed.

On the one hand, an oil supply cushion exists in the world today, and any serious supply problem in the immediate future appears to be extremely unlikely. This is true in spite of the ongoing war between Iran and Iraq, which is preventing substantial potential oil production and is providing a continuing reminder of possible disruptions in oil supplies from that volatile part of the world.

On the other hand, the long-term future is much less certain. The national energy climate is unsettling. Lethargy and complacency have returned. Memories are short. The sense of urgency that existed in Washington and among the public has largely vanished.

Optimists -- including those who are disinclined to plan for the future -- tend to overlook or discount this lethargy and complacency. Pessimists -- including those who discount our recent progress -- see an energy future that is grim indeed.

Realists recognize both the potential dangers and the fact that the future need not be bleak -- if appropriate decisions concerning energy are made.

Here are some current facts about the nation's oil-import situation:

- Right now there is a huge excess of oil-producing capacity in the world. This surplus averaged about 15 million barrels a day in the first quarter of 1983. But turnarounds come with unbelievable swiftness. As the 1970s ended, less than four years ago, excess capacity in the world was less than one million barrels a day -- only 1 or 2 percent more than demand. A shift back toward a tight market could create severe problems for all oil-importing countries, including the United States.

- Oil still accounts for nearly one-half of all the energy Americans use, and, despite the recent progress, in 1982 foreign oil still accounted for nearly one-third of our total oil supply. The volume of imports has declined but our nation's 1982 oil import bill was a whopping \$60 billion -- over 13 times the amount a decade earlier.

• Although the share of oil imports from the Middle East has fallen in recent years, existing proved reserves of oil are still predominantly in the Organization of Petroleum Exporting Countries (OPEC) -- mainly in the Middle East. As national -- and worldwide -- economic recovery occurs, the demand for additional supplies will increase, and our vulnerability will grow. Considering the volatility of the Middle East, and knowing that our oil imports are only marginally less than they were in 1973, one cannot feel comfortable.

And what about the situation at home today: What important decisions on energy are being made -- or left unmade?

More than three-quarters of the domestic oil that the nation will be using in the year 2000 -- not 2050 -- will have to come from oil fields that have not yet been found.

If new discoveries falter, the United States could again become excessively dependent on foreign oil -- and more likely experience higher prices and possible shortages. So, it is still critically important today to develop and pursue policies that will enhance prospects for future development of domestic oil -- and other energy resources, as well.

Yet, future supplies of oil will be harder to find and more costly to produce than in the past. No one can tell for certain, but many observers believe there are no more really huge, low-cost fields waiting to be found. It is the remote and environmentally hostile areas that now offer the best prospects -- areas such as the arctic and deep offshore waters -- where the cost of finding and producing a barrel of oil is many times greater than in the Middle East.

But widespread inertia and reluctance to face now the problems of the future are not enhancing those or other prospects for future energy security. In fact, they have actually created an atmosphere conducive to new, counterproductive policies. These are some of the problems:

• Crude oil production may have peaked and certainly will decline further unless the industry is allowed to expand its exploration efforts especially on largely untapped federal lands. Yet millions of acres of federal lands onshore, with the potential to produce vast amounts of oil and natural gas, are being locked up. Offshore, prior to the beginning of the current Five-Year Outer Continental Shelf Leasing Program, only 5 percent of all federal lands had been offered for leasing and only 2 percent of those lands had been leased. Even with a substantial increase in the acreage offered since June 1982 -- more than one-half of all the federal OCS lands offered to date -- only about 3 percent had actually been leased by June 1983. Yet some of the small areas that have been developed offshore

-- especially in the Gulf of Mexico and off California -- now produce about a quarter of the nation's domestic natural gas and about 10 percent of our crude oil and natural gas liquids. Recently, several companies drilling off the coast of Southern California made what may turn out to be the largest discovery ever in federal waters. In spite of the vast potential, proposals are being considered to lock up much of the federal offshore acreage now scheduled for possible leasing, including many of the areas believed to hold the greatest potential for oil and gas discoveries.

- Despite the now almost-undisputed benefits of crude oil decontrol to the nation as a whole and to individual consumers, the outlook for natural gas deregulation is far from certain. Despite the hard-learned lesson of the 1970s, many policymakers continue to reject a market system for gas.

- At current prices and levels of taxation, the oil industry faces many challenges -- not the least of which is capital for needed investment. Too many persons in too many places ignore the fact that the oil crisis is not over and that the industry's success in reversing the decline in U.S. production and diversifying foreign sources of supply would be seriously jeopardized by new or increased taxes. New special taxes are still being proposed for the oil industry, and some states have recently imposed such taxes.

- The Clean Air Act and the Clean Water Act need to be modified so that their goals can be accomplished more efficiently and so that unintended and unnecessary adverse effects on energy development and economic stability are avoided. Yet such improvements are unlikely; indeed, changes now under consideration would add to the complexity of these laws.

- In addition, public policies have long hampered development of the coal industry and have virtually halted all development of the nuclear power industry -- at a time when a commercial synthetic fuels industry has become less economically viable and may not come into being until after the turn of the century -- at least 10 years later than most experts had thought. Only a few sources, such as solar and geothermal energy, are progressing, and they are likely to remain very small contributors to U.S. energy needs for at least a decade or more.

Instead of pursuing the obvious solutions -- natural gas decontrol, recognition of the need to develop energy on federal lands, fair taxation, and more rational and balanced environmental regulations, for example -- federal and state political leaders tend to feel that solutions are not necessary or that those solutions would have too high a political price.

So, there is great uncertainty about the nation's energy prospects.

Consider some possibilities for the future:

What if economic recovery is more vigorous and more energy-intensive than generally expected? What if a major political upset in the Middle East once again curtails oil supplies? What if the development of other energy resources, now weakly alive, comes completely to a halt?

Given current worldwide excess oil production capacity it would take such events, on a large scale, to put oil-importing nations into jeopardy over the next year or two.

As a result, many people discount the need for solutions. They find solace in the popular view that emerged with the excess production capacity: that OPEC has lost its power and that there is nothing it can do to prevent a downward spiral of oil prices. However, by mid-1983 world oil prices appeared to have stabilized. OPEC's difficulties, after all, developed during a very deep and protracted recession which now appears to have ended.

As demand picks up during economic recovery, OPEC's prospects are likely to brighten. If OPEC countries do not increase production sufficiently when demand increases, the market could tighten and prices could rise. Further, a cutoff of oil from the unstable Persian Gulf region could cause sudden price increases and major energy problems worldwide.

So, for American consumers, OPEC still has much influence over oil prices. The best safeguard against possible future price increases, spurred by OPEC in a tighter market, is to take the initiative in conserving and producing as much energy as we can here at home.

In the absence of government interference -- that is, with policies that foster, rather than hamper, competitive markets -- the marketplace will achieve an equilibrium that minimizes the prospect of such disruption.

However, as important as the market is in pointing us to the future, it is not the only actor on the economic stage. For all sorts of reasons, governments adopt policies that nudge economic developments in one direction or the other. They raise revenues, encourage selective economic development, combat inflation, protect the environment, adjudicate competing social claims and do dozens of other things that affect the conduct of business.

We also must remember that roughly half of the world's supply of oil is under the control of governments. And when

governments make market decisions, politics can -- and often do -- become a greater consideration than economics.

The essential questions are:

- "Could there be a repetition of the misery of 1973?"
- "Will the decisions of today prove consistent with the needs of tomorrow?"

The answer to the first question is that there appears to be little likelihood of a repetition of 1973 in the next year or so, barring severe disruptions in the Middle East. The answer to the second question is much less certain. Clearly the energy industry and the consuming countries have gained more time in which to prepare for an unknown future. But it would be unwise to assume that the energy problem has gone away.

It is important to note that, despite the oil discoveries of the past decade and the falloff in oil consumption rates for more than a decade, the world has been consuming more oil than it has been finding. There is no evidence that this trend is about to reverse itself.

Nonetheless, it is clear that the current adequate energy supplies are weakening our resolve to prepare for the future.

In the national perception of the problem, the mood once again is that solutions can be ignored and that further complications can be introduced without the nation needing to pay a serious price.

When the first edition of Two Energy Futures was issued in 1980, few observers foresaw the progress that would occur over the next few years. Most people thought that the nation's energy future was grim indeed.

But the premise of Two Energy Futures was that the United States had a choice: that we had vast energy resources, that we had the ability to produce more of that energy efficiently at home and to use all energy more efficiently, and that we could, therefore, significantly cut our dependence on oil imports and attain a more secure energy future. We could do these things, provided we made the right policy choices as a nation. That premise proved not only valid, but also more readily realizable than most people thought. The policy choice to decontrol crude oil and petroleum products set in motion a salutary chain of events.

Today, however, the United States risks slipping back toward its dangerous position of the 1970s. Today, future progress in both conservation and domestic production of energy

is less certain. Economic recovery will likely increase domestic energy consumption, while complacency about energy needs will likely hamper further sound policy decisions.

But, again, the United States has a choice: it has the domestic energy resources to sustain economic growth and to remain more secure from the dangers of great dependence on uncertain supplies of foreign oil.

Again, it has the choice -- as it did at the beginning of the 1980s -- to pursue policies that will assure greater energy security through the 1990s -- or policies that will cause us to slide back toward the insecurity we faced during the past decade.

Today, at a time when the nation faces the choice of either consolidating and advancing its recent progress or retreating into the more precarious position of the 1970s, the premise of Two Energy Futures remains just as valid as it was in 1980.

The history of the past several decades, especially of the 1970s -- and, now, of the first years of the 1980s -- affirms that the American people have energy choices available and underscores the importance of our choosing wisely among them.

The 1950s, 1960s and 1970s: Energy Security to Energy Dependence

America had secure supplies of energy during the 1950s and 1960s -- a time of unprecedented economic growth and a rising standard of living in this country.

The 1970s, however, were a period of transition to grimmer times. Domestic oil and natural gas production began to fall. Our dependence on uncertain foreign oil rose rapidly -- from 3.4 million barrels a day in 1970 to 8.4 million barrels a day in 1979, or nearly half of U.S. petroleum consumption. Worldwide, during the 1970s the availability of oil imports became subject to the goodwill and political stability of a few oil-exporting countries. It also became subject to the smooth passage of oil tankers across thousands of miles of exposed ocean and through many vulnerable "choke points" along their routes.

The impact of a cutoff of part of those supplies was felt during the 1973-1974 embargo and again during the 1979-1980 Iranian revolution. As a result of limited supplies and federal price and allocation controls, gasoline became difficult to obtain. And, largely because of the economic and political power of the oil-exporting countries in the '70s, the cost of foreign oil was driven up sharply during the decade -- costs of driving cars, heating homes and running factories rose

rapidly. The U.S. oil import bill increased from \$3 billion in 1970 to almost \$80 billion in 1980.

Reliance on oil imports, like reliance on other imported products or commodities, is not intrinsically bad for the nation. But the insecurity of oil imports made the United States unnecessarily vulnerable. America's future energy security depends on its ability to hold that dependence to an acceptable level.

During the last three years, our energy situation has improved significantly. The removal of price controls on domestic oil was a successful step toward that improvement. During that time, U.S. energy production has risen and consumption has fallen. By the beginning of 1983, imports were down more than 40 percent from 1979. Still, in 1982 foreign oil accounted for 32 percent of all the oil Americans used. And, despite the decreased volume of imports, the 1982 oil import bill was \$60 billion -- over 13 times the amount a decade earlier.

Although the nation is more energy-secure today than it was during most of the '70s, a cutoff of foreign oil supplies could again create problems like those we faced then -- we could still find ourselves suddenly paying dramatically higher prices, in dollars and economic disruption, for oil imports. Even without a cutoff, American consumers still must send too many dollars abroad, and the United States continues to face the risk of reduced national security and a less flexible foreign policy.

The 1980s: A Decade of Choice

But the dependence on oil imports of the '70s need not be a permanent feature of our lives -- as the substantial progress of the first years of the '80s makes clear. We can consolidate this progress and further strengthen our energy security if we continue to face up to the reasons for the difficulties of the '70s.

There have been twin causes for our problems: The United States has used too much energy and has not produced enough. The attainable, practical way out requires that we continue our recent efforts, so that more domestic energy can be produced and all energy can be used more efficiently.

The experience of 1980-1983 is persuasive evidence that dramatic progress in cutting imports is possible. And recent "best case" studies by energy specialists in government, business, industry and academia confirm that maintaining a much-reduced level of oil imports through the '80s is a reasonable course for America.

This report discusses the contributions which analysts think can come by 1990 from various energy sources: oil, natural gas, coal, nuclear power, synthetic fuels, and renewable sources such as solar energy -- if the right policies are pursued in a timely way.

This introduction serves as a summary and a documentation. Other chapters go into detail on oil and natural gas, coal, nuclear energy, synthetic and renewable fuels, conservation, the environment, use of government lands, the economic benefits of an improved 1990 energy position and what that improvement could mean to the individual. Throughout this report the most current appropriate data have been used, although the time periods of the data may vary from section to section. A list of sources consulted is also included.

Energy Resources of the United States

Although conventional sources of energy in the United States are finite, they can last for decades more. In the case of coal, which can be converted to oil and gas, U.S. resources could last for centuries.

More specifically:

- Government and industry studies indicate that the United States can expect to produce about 164 billion barrels of crude oil and natural gas liquids in the future -- more than this country has ever produced.¹ ("Natural gas liquids" are liquid petroleum that results from production and processing of natural gas.)
- The same studies indicate that remaining natural gas reserves plus future discoveries could total more than 970 trillion cubic feet -- well over 50 percent more gas than the nation has ever produced and the equivalent of nearly 170 billion barrels of oil.²

These amounts of oil and gas are the equivalent of about 44 times more petroleum and natural gas liquids and 55 times more natural gas than the United States produced in 1982.

- Total recoverable reserves of coal are around 237 billion tons (the equivalent of about 911 billion barrels of oil) -- almost three times greater than our recoverable resources of oil and gas.³
- Recoverable reserves of uranium are about 889,000 tons -- enough to sustain the nuclear power industry well into the 21st century.⁴

In addition, the United States has vast quantities of relatively high-grade shale oil -- which could begin to make a con-

tribution by 1990, if appropriate economic conditions exist. Past estimates suggest these may amount to as many as 600 billion barrels.⁵ This amount is almost twice as great as our oil and gas resources. And we can also ultimately expect contributions from renewable and other sources, such as solar energy, geothermal energy and biomass.

Beyond these energy sources, the United States has another tremendous resource -- conservation -- that has already dramatically reduced our dependence on imported oil. A few years ago most people thought of conservation as simply "doing without," and many experts believed there was little opportunity to reduce energy consumption without economic hardship. The experience of the past few years -- as consumers have adjusted to rising prices -- has greatly altered this belief.

In brief, the United States has ample resources to meet its energy needs. The issue is how effectively the nation will choose to use them.

Outlook for 1990: Progress or Crisis?

Good use must be made of these vast resources in the years ahead in order to keep imports from rising while sustaining a reasonable rate of real economic growth -- perhaps at an average annual rate of 3 percent. Even better use must be made of them if we are to continue to reduce oil imports by 1990. As noted, conservation will make a major contribution. However, even with the improved levels of conservation that we have seen in the last two years or so, new supplies of energy will be required to satisfy the nation's future energy needs. Recent projections by some who advocate and expect substantial additional conservation still indicate that the United States will need from 13 to 22 percent more energy in 1990 than it used in 1982 to meet the needs of a growing population and economy.⁶ In short, there is no acceptable way of "saving our way out."

But, according to the recent "best case" studies mentioned earlier, by acting wisely and choosing to develop and use domestic resources more efficiently, we could:

- maintain U.S. oil production close to 1979 levels at about 9 million to 10 million barrels a day;⁷
- maintain natural gas production close to 1979 levels at the equivalent of about 8 million to 9 million barrels of oil a day;⁸
- double our use of coal by 1990 to about 13 million to 14 million barrels a day of oil equivalent;⁹

- increase the contribution of nuclear power by 1990 to 2.5 million to 3.5 million barrels a day of oil equivalent;¹⁰ and
- get new production from synthetic fuels, shale oil, renewable sources and others -- increasing total production to perhaps 1.5 million to 3.0 million barrels a day of oil equivalent, depending upon energy prices.¹¹

With production of domestic energy at those levels -- along with sensible but not austere conservation -- the United States could maintain a much-reduced level of oil imports through the '80s.

Of course, the actual "energy mix" doubtless would turn out to be somewhat different than given above. We could end up with more than suggested from some energy sources and less from others. No one can look so far ahead with precision. The important point is that the production ranges cited are reasonable, if the nation chooses to take the right steps.

So far during the 1980s, net energy progress has been encouraging. Oil production increased and drilling for new oil and gas rose to an all-time high; coal production increased; but development of shale oil and other synthetic fuels lagged, with the decline of oil prices. At the same time, Americans have been conserving energy. As a result, imports were dramatically reduced from 1979 levels.

The results of sustaining recent progress and further reducing imports would be dramatic. Americans would have more secure supplies of energy for cars, homes, factories and jobs. We would see less pricing power in OPEC than in the past. The national economy would be on a sounder footing. Our internal and foreign affairs would be more free from the threat of energy blackmail by foreign governments or terrorist groups. We could adjust more readily to a supply interruption like the 1973-1974 oil embargo or 1979 Iranian oil export cutoff.

Although the outlook today is more encouraging than it was several years ago, there is no assurance that we will sustain recent progress. The more optimistic projections depend on continued progress in solving remaining difficulties.

Policy Choices for the 1980s

Maintaining the current improved course does not assume any major technological breakthroughs -- only continued technical progress. It requires basically that unnecessary government regulatory roadblocks, red tape and delays will be substantially reduced, that there will be no further special taxation of the energy industries which has the effect of curtailing

energy production and that the market will have more opportunity to choose the most economic options. And it requires that, because of the long lead times needed to bring major new energy projects into production, improvements in government policy will be made in a timely way.

Specifically, government policies should include:

- gradual decontrol of all domestic natural gas production;
- more access to energy on federal lands;
- a more careful balance between continued environmental progress and U.S. energy development;
- consistent government decisions that reduce uncertainty and encourage reasonable growth in nuclear power;
- increased reliance on the market system;
- tax policies -- federal, state and local -- which do not discriminate against the energy companies; and
- encouragement of the development by the private sector of synthetic fuels, including construction of pioneer plants incorporating synthetic fuel technologies.

With these policies, imports can be held at lower levels and even further reduced in this decade -- to half of their level at the end of the energy-disastrous '70s. This is not a promise, prediction or forecast of what will happen. Instead, it is a realistic description of what the nation's energy situation could be -- if the right choices are made and actions taken.

The actions required are logical and feasible -- but not easy for the political system or for producers or users of energy. The nation, through its political process, may reject any or all of the energy opportunities it has. But the opportunities for significant change continue to exist.

The critical point is for the country to recognize the disadvantages which result from heavy dependence on imported oil and to continue to move in the direction of Americans having more control over their own energy affairs.

Documentation of a 1990 Improved National Energy Posture

Two basic sets of numbers are used throughout this discussion of 1990 -- a 1990 "base case" and a 1990 "accelerated case." It is important that the two not be confused. (The sources consulted in preparing the sets of numbers are identified on pages 209-210.)

One set -- the 1990 base case -- consists of projections published by government agencies, petroleum companies and other institutions. These reflect what the analysts think will happen. Some analysts give a range -- low, middle and high cases. Others offer just one number.

The projections differ because each was made at a different time and because each used different assumptions about economic, environmental, technical and government factors. Explanations of these assumptions are not always detailed and often missing. Conversion factors -- from actual energy units (tcf, ton, etc.) or Btus to million barrels a day of oil equivalent (mbde) -- also differ somewhat from study to study.

It should be noted that none of these analysts knows precisely what U.S. energy production will be in 1990. With oil and gas, for example, no one can know without additional exploration and drilling.

Another set of figures is used throughout this discussion to describe the 1990 "accelerated case" that could exist in a different energy world. These numbers are not forecasts or predictions and do not represent what will happen in 1990 or even what is likely to happen. Rather, they reflect what appears to be achievable, given the resources of this nation, if the right decisions are made.

The following table, condensed from a more detailed version appearing on page 25, presents the situation that existed in 1979, the base case and the most recent accelerated case for 1990.

UNITED STATES ENERGY¹²
(all numbers in millions of barrels a day or
millions of barrels a day of oil equivalent)

	1979	1990 Base Case*	1990 Accelerated Case
Crude Oil/NGL	10.1	7.9 - 9.7	9.0 - 10.0
Natural Gas*	9.5	7.1 - 9.2	8.0 - 9.0
Coal*	7.1	9.4 - 11.6*	13.0 - 14.0*
Nuclear	1.3	1.4 - 3.8	2.5 - 3.5
Hydro	1.4	1.3 - 1.8	1.3 - 1.8
Other*	0.04	0.2 - 0.9	0.2 - 0.9
Shale Oil	0	0 - 0.11	0 - 0.11
Consumption*	37.3	38.0 - 40.8	38.0 - 39.0
Oil Imports*	8.4	5.5 - 7.9	3.5 - 5.5

*See footnotes to expanded table on page 25.

The accelerated case, a composite of "high supply" and "low demand" projections, assumes much more efficient use of our energy resources. It suggests the course the nation might follow if the public became more involved with the country's energy situation, if informed Americans supported government policies designed to remove obstacles to domestic energy production and if such people influenced government to make those decisions.

Federal and state governments cannot be expected to make all needed changes in policy overnight and move with speed to a "perfect" energy course.

But clearly there will be much more movement if the nation is determined to improve its energy condition. There can be more movement than many planners think there will be. Thus, the accelerated case described for 1990 -- the case that could hold imports at current levels or perhaps even reduce them further -- is drawn from the possible, not from the anticipated.

The accelerated case is not "blue sky." It is reasonable and reachable in the 1980s.

Because some of the projections and studies produce ranges, and because no one knows what will happen by 1990, the accelerated case in this paper for each energy source is presented as a range.

The wide range shown in the projections is evidence that the nation cannot plan rigidly on the basis of any particular energy projection -- whether pessimistic or optimistic. The wise course is to take necessary steps to determine what our domestic energy resources are and to maximize their economical production.

The production of some sources may fail to reach the levels of the accelerated case. Others might exceed projected levels or conservation might increase. In any case, the nation will still be better off in 1990 for having tried now to improve its energy situation. And, of course, it must be recognized that there is nothing unique about the year 1990. Energy progress can be continual, from now until then and beyond.

Following are details supporting the accelerated production levels for oil, natural gas, coal, nuclear power, synthetic fuels and renewable energy sources. Also included are details on expected energy consumption.

Oil and Natural Gas

For well beyond the coming decade, oil and natural gas will be principal sources of energy in the United States. The issue is now large a contribution they will make. The size of that contribution will depend in large part on what government decisions are made.

During the 1970s, the nation used considerably more domestic oil and natural gas than it found, and production declined.

Domestic oil and natural gas liquids production peaked at 11.3 million barrels a day (mbd) in 1970 and declined to 9.7 mbd in 1976 -- increasing slightly to 10.1 mbd in 1979. Natural gas production peaked at about 10.5 million barrels a day of oil equivalent (mbde) in 1973 and declined to 9.2 mbde in 1978 -- increasing slightly to 9.5 in 1979.

Since then, the domestic oil decline has been slowed by the advent of Alaskan North Slope oil, which began flowing through the trans Alaska oil pipeline in 1977. Also, higher prices have helped stop the decline in production in the lower 48 states. As a result, total U.S. production of oil and natural gas -- including Alaska -- has leveled out over the past few years. However, further discoveries will be required to maintain North Slope production over the long term and to continue progress in the lower 48 states.

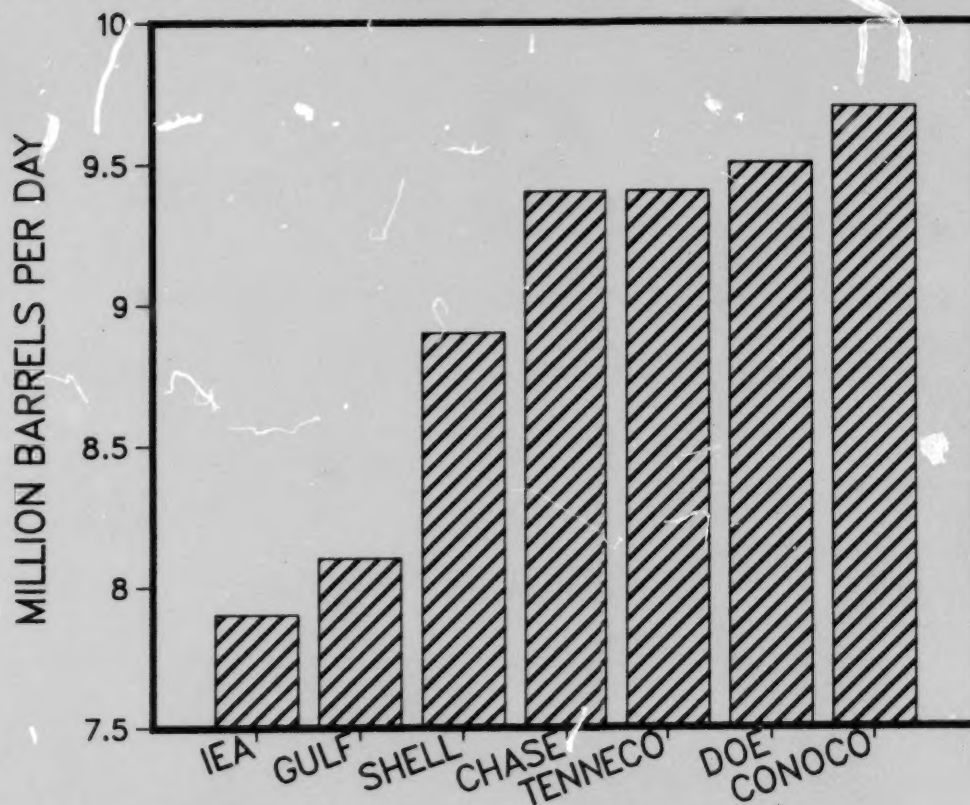
While exploratory results so far in such areas as the Gulf of Alaska, the Baltimore Canyon off the New Jersey coast and Georges Bank off New England have not been encouraging, results elsewhere, especially in several Rocky Mountain areas and off the west coast, have shown considerable promise. Most large new domestic discoveries of oil and gas are still likely to be in the western states, in Alaska and on the Outer Continental Shelf (OCS).

Under current conditions, lead times between initial exploration and first production in some areas are estimated to be 8 to 11 years. Thus, rapid exploration and development of the oil and gas resource potential of the western states, Alaska and the OCS are essential. The rate of production growth in these areas will depend largely on governmental leasing and regulatory policies.

As indicated, the accelerated case in this paper assumes that those governmental policies will be improved.

The studies reviewed for the base projections in this paper show a potential 1990 range of 7.9 mbd to 9.7 mbd of crude oil and natural gas liquids production. (See graph, "Crude Oil and Natural Gas Liquids Projections.")

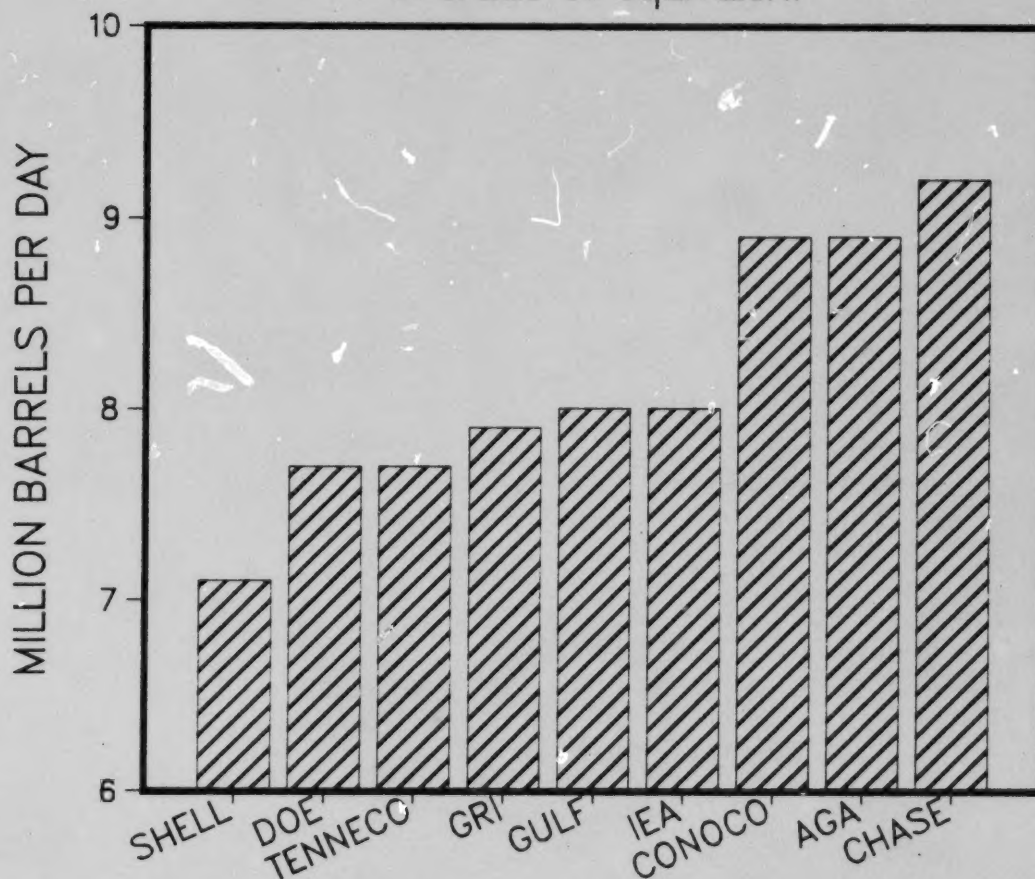
CRUDE OIL AND NATURAL GAS LIQUIDS PROJECTIONS OF 1990 PRODUCTION



SOURCE: SEE APPENDIX

For natural gas, they show a 1980 range of 14.6 trillion to 19 trillion cubic feet a year (7.1 mbd to 9.2 mbde). (See graph, "Natural Gas Projections.")

NATURAL GAS
PROJECTIONS OF 1990 PRODUCTION
in crude oil equivalent



SOURCE: SEE APPENDIX

Following are the 1990 domestic crude oil production studies and projections which are used in this study. They are from oil companies, the government and other sources. All were published in the second half of 1982 and in 1983.

PROJECTIONS OF 1990 PRODUCTION¹³
CRUDE OIL & NATURAL GAS LIQUIDS
(millions of barrels a day)

International Energy Agency	7.9
Gulf Oil Corporation	8.1
Shell	8.9
Chase Econometrics	9.4
Tenneco	9.4
Department of Energy	9.5
Conoco	9.7

Following are the 1990 natural gas projections, also published in 1982 and 1983, which were used in this study.

PROJECTIONS OF 1990 PRODUCTION¹⁴
NATURAL GAS
(millions of barrels a day of oil equivalent)

Shell	7.1
Department of Energy	7.7
Tenneco	7.7
Gas Research Institute	7.9
Gulf Oil Corporation	8.0
International Energy Agency	8.0
American Gas Association	8.9
Conoco	8.9
Chase Econometrics	9.2

Using the projections in these studies as a base, the accelerated case in this report suggests the possible 1990 production of some 9 mbd to close to 10 mbd of crude oil and natural gas liquids and some 16.5 trillion to 18.5 trillion cubic feet of natural gas a year (8 mbde to 9 mbde). At these rates, both oil production and natural gas production would remain near current levels.

Coal

There is widespread agreement that coal use can and must increase through the 1980s. The size of the increase is a much more difficult question, although a supportable best case shows that coal use can about double.

In 1979, the United States consumed about 680 million tons of coal, or 7.1 mbde. The Department of Energy's (DOE) 1982 Annual Energy Outlook estimates a 1990 midrange for coal use of 9.5 mbde.¹⁵ On the other hand, a National Coal Association forecast for 1990 coal consumption shows a most likely case of about 1.1 billion tons, or about 11.6 mbde and a high case of about 13.3 mbde.¹⁶

Therefore, nearly doubling coal use by 1990 appears to be reasonable for the accelerated case, which assumes energy-conscious government decisions.

Nuclear Energy

Defining an accelerated case for nuclear power generation is particularly difficult, given the intense emotion that has surrounded the issue over the past few years and the political impact of the accident at Three Mile Island in 1979. With timely siting, permitting and construction, huge increases in nuclear power are possible -- and huge increases were predicted in the early 1970s. Even after problems and longer-than-anticipated lead times began reducing that optimism, projections in 1975 and 1976 showed nuclear power quadrupling by 1985 and increasing sevenfold by 1990.

Projections made later, in 1977-1978, still showed strong growth but substantially less than earlier. As would be expected, more recent projections since the Three Mile Island accident and its aftermath are more pessimistic.

Little support now can be found for a 1990 case reflecting the earlier optimism. Furthermore, lead times are such that even a rapid change in policies may add relatively little growth by 1990. Such a change could, however, have a large effect beyond 1990.

Considering only the more recent data -- not the projections of the early and mid-1970s -- more than a doubling and perhaps close to a tripling of nuclear power generation by 1990 seems to be a realistic expectation.

Current DOE projections for 1990 show an estimate of about 3 mbde.¹⁷ This would more than double nuclear energy by 1990, from the 1.3 mbde in the base year of 1979.

The Atomic Industrial Forum's latest projection shows an increase in installed capacity, based on current commitments, by a factor of close to 2, compared with 1982.¹⁸ The factor would be a little over 2 if all reactors under construction and ordered could be completed by 1990.¹⁹ Moreover, the nuclear industry expects plants, on average, to operate a higher per-

centage of the time than they have recently. Thus, actual generation would be about 2.6 mbde in 1990.

In sum, most analysts appear to agree that nuclear power generation will double by 1990, reaching around 2.5 mbde.

However, some analysts do show higher figures. For example, figures from the current estimate of the North American Electric Reliability Council, a utility group, show an increase in actual generation to about 3.8 mbde by 1990.²⁰

The situation is still unsettled and the longer term effects of government policy are not yet clear. Even if the government helps to resolve issues involving nuclear plant construction, some plans for new plants may slip past 1990.

Reflecting this enormous uncertainty, a reasonable accelerated case is considered to be about 2.5 mbde to 3.5 mbde. The important improvement in the accelerated case is that the large government policy uncertainties would be resolved, so that the nation would be much more confident of reaching these production levels. Of course, if nuclear power experiences major unforeseen problems -- such as a renewed, lengthy moratorium -- the 1990 import reduction of the accelerated case would not be met.

Synthetic Fuels and Shale Oil

With synthetic fuels and shale oil, today's estimates cover a lower range than in previous years. This is because estimates were scaled back as the drop in oil prices caused plans to be cancelled or delayed.

Various published government and industry data show potential production of individual fuels as follows: liquids from coal, 0 mbd to 0.03 mbd; gas from coal, 0.03 mbde to 0.14 mbde; and shale oil, 0 mbd to 0.11 mbd.

Thus, a total of 0.03 mbde to 0.28 mbde was taken as a reasonable and supportable range for synthetic fuels and shale oil production.

Solar, Hydroelectric, Biomass, Geothermal Energy

The remaining energy sources -- solar, hydroelectric, biomass and geothermal -- are relatively small, both in current and projected 1990 production. Most projections group them in a single category or just deal with hydropower.

These sources currently supply about 1.6 mbde, mostly from hydroelectric power. Several private and government projections indicate a range of 1.3 mbde to 1.8 mbde in 1990 for

hydroelectric power alone and a range of 0.2 mbde to 0.9 mbde for all of the other sources.

Thus, for this paper, for 1990, a range for hydropower of 1.3 mbde to 1.8 mbde and 0.2 mbde to 0.9 mbde for geothermal, solar and biomass production was taken as being reasonable and supportable as an accelerated case.

Achieving the full potential of solar energy will require technological improvements to reduce current costs. Thus, analysts expect that a substantial solar contribution will come later than 1990.

Consumption

Projections of U.S. energy consumption levels have been dropping steadily over the past several years. Conservation from higher prices has been taken into account in virtually all recent studies. Significant energy conservation beyond current projections would appear to depend on sharply higher prices or government mandates or subsidies that go far beyond those already in effect.

A majority of the studies reviewed here, which were done in the second half of 1982 and in 1983, project energy demand to grow at an average annual rate of somewhere between 0.5 percent and 1.2 percent between 1981 and 1990. This is substantially slower than the rate of growth in the 1960s and 1970s.

For example, one of DOE's projections, published in 1983, shows a consumption figure of 38 mbde in 1990, which is about 13 mbde lower than the comparable estimate of only 6 years earlier.²¹ This holds true for other forecasts for 1990 as well. (See graph, "Projections of United States Energy Consumption," which compares projections made in past years.)

The U.S. energy consumption levels for the 1990 accelerated case range from about 38 mbde to 39 mbde, compared with 1982 consumption of about 33.5 mbde and 1979 consumption of 37.3 mbde.

Import Reduction Steps

In the accelerated case for domestic energy production and consumption, the import balance sheet would be affected in the following ways:

- If the production of oil and natural gas is stabilized near 1979 levels, then oil and natural gas imports would be lower than otherwise.

- The increased coal production would permit coal to displace oil and natural gas in utilities and industry, with the gas then used elsewhere in place of oil. This would reduce the demand for imports.
- New coal-fired power plants, nuclear power, geothermal and renewable sources (hydroelectric, solar and biomass) will meet increasing demand for electricity, so that this higher demand will not require additional oil imports.

Under that schedule, 1990 oil imports could be reduced beneath what they would otherwise be. As noted, this reduction could hold imports at current levels -- close to a 50 percent reduction from their 1979 level of 8.4 mbd -- or perhaps even reduce them further.

The "United States Energy" table (at the end of this chapter) summarizes domestic energy production and consumption. It compares the situation in recent years, the range of recently published projections and the accelerated case which is reasonable for 1990 if government policies continue to be improved.

Conclusion

In conclusion, several points about the 1990 U.S. energy situation should be re-emphasized:

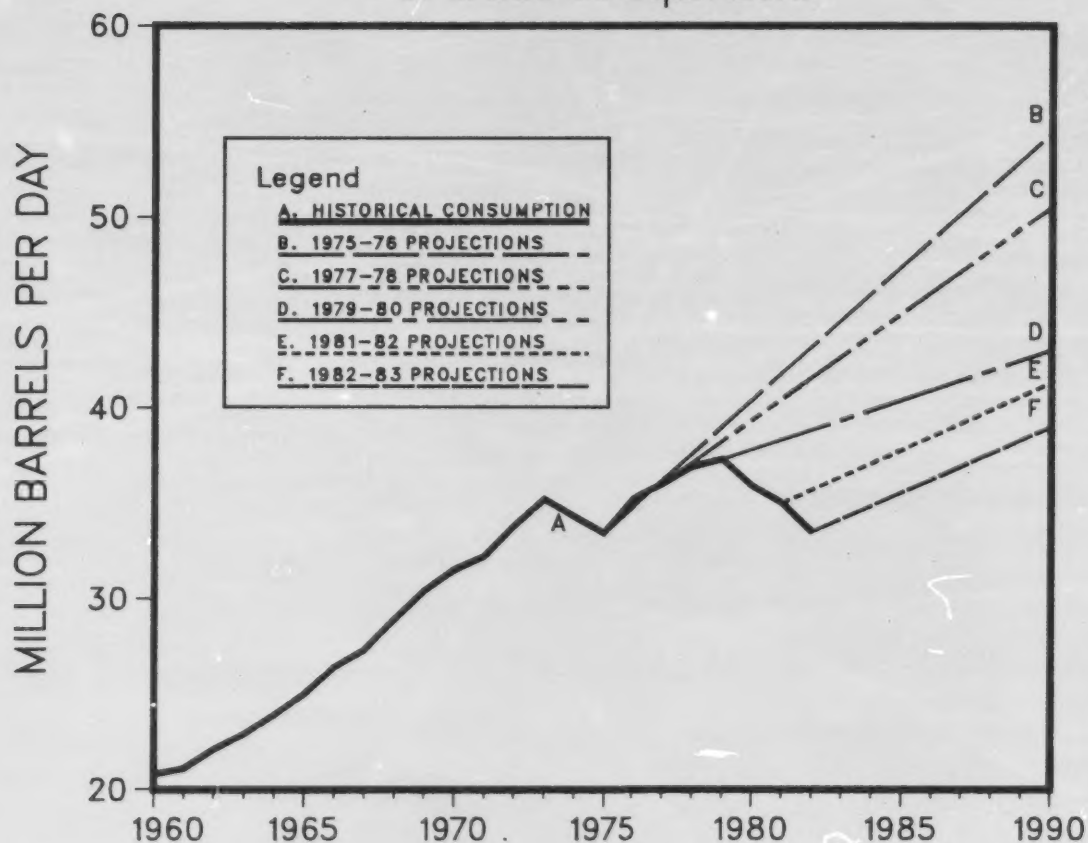
- This report speaks of the feasibility of holding imports at current levels or perhaps even reducing them further. The final result might be a reduction of 54 percent or 43 percent from the 1979 level. No one -- no forecaster, planner, economist, engineer, geologist or geopolitician -- knows what 1990 will look like. This is evident not only from common sense but from the great variations among energy projections. So, energy decisions should be made with this uncertainty in mind. Whether or not a further import reduction is actually achieved, it will be important in 1990 that the nation acted to realize its potential during the 1980s.

- This report cites ranges of possible 1990 production of the different energy sources in the accelerated case. Clearly there is nothing certain about that specific energy mix. Some planners will regard several of the accelerated case numbers as high and others as low. And, in 1990, the scorecard may actually show somewhat less natural gas, somewhat more coal, some unexpected progress in synthetics. But all resources should be developed efficiently, and continued conservation is essential. Given the energy studies and projections reviewed in this report, the ranges used for the accelerated case are within reach.

• While these ranges are reasonable, they will not be easy to attain. Enormous efforts will be required by the energy industry to reach even some of the lower production levels of the 1990 accelerated case.

• Finally, this report does not set a goal and then calculate how to reach it. Rather, it examines the resource base, studies various projections to derive consensus figures, analyzes current government policies which inhibit domestic production, cites general areas of policy change and, on a foundation built of those ingredients, describes what the overall U.S. energy situation could be by 1990 and what must be done to get there.

PROJECTIONS OF UNITED STATES ENERGY CONSUMPTION in crude oil equivalent



SOURCE: SEE APPENDIX

As the past three years have shown, an increasing dependence on imported oil is not inevitable. The nation can continue to lessen that dependence significantly.

Clearly, movement toward reduced dependence on imports provides significant benefits for Americans as individuals and for this nation as a whole. These benefits include a stronger dollar, improved balance of payments, strength to inhibit political blackmail from abroad, more security against disruption of our vital oil supplies, more goods and services and less inflation.

UNITED STATES ENERGY²²
(all numbers in millions of barrels a day or
millions of barrels a day of oil equivalent)

	<u>1979</u>	<u>1980</u>	<u>1981</u>	<u>1982</u>	<u>1990</u> <u>Base Case^a</u>	<u>1990</u> <u>Accelerated Case</u>
Crude Oil/NGL	10.1	10.2	10.2	10.2	7.9 - 9.7	9.0 - 10.0
Natural Gas ^b	9.5	9.5	9.4	8.5	7.1 - 9.2	8.0 - 9.0
Coal ^c	7.1	7.3	7.6	7.3	9.4 - 11.6 ^d	13.0 - 14.0 ^d
Nuclear	1.3	1.3	1.4	1.5	1.4 - 3.8	2.5 - 3.5
Hydro	1.4	1.4	1.3	1.5	1.3 - 1.8	1.3 - 1.8
Other ^e	0.04	0.1	0.1	0.1	0.2 - 0.9	0.2 - 0.9
Shale Oil	0	0	0	0	0 - 0.11	0 - 0.11
Consumption ^f	37.3	35.9	35.0	33.5	38.0 - 40.8	38.0 - 39.0
Oil Imports ^g	8.4	6.9	5.7	4.9	5.5 - 7.9	3.5 - 5.5

a Midrange of recently published projections.

b Excludes imports.

c Excludes exports.

d Excludes exports of 1.4-2.0; includes 0-.03 liquid synthetics, 0.03-0.14 gas synthetics.

e Includes solar, biomass and geothermal.

f Consumption does not equal production plus imports because of changes in stock levels and inclusion of product imports and NGL by volume, as commonly reported, rather than as crude oil equivalent.

g Excludes Strategic Petroleum Reserve.

II. OIL AND NATURAL GAS

Oil and natural gas together have provided more than half of the energy used in the United States in each year since 1947. Their combined contributions rose to nearly 78 percent of total energy consumption by the early 1970s.¹ By 1982, the figure for oil and gas had dropped to 69 percent of the total, reflecting gains by coal, nuclear energy and hydroelectric power during the past decade.²

In 1982, the U.S. Department of Energy (DOE) estimated that petroleum provided nearly 43 percent of U.S. energy consumption; natural gas, 26 percent; coal, nearly 22 percent; hydroelectric power, 5 percent; and nuclear energy, slightly more than 4 percent. All other sources, including geothermal power and electricity generated by burning wood and waste, accounted for a small fraction of 1 percent of the total. Nearly 90 percent of the energy used in the United States was also produced in this country.

Some analysts believe that more oil and natural gas will be produced in America in future years than in all of the past. And all analysts agree that oil and natural gas will be principal sources of energy in the United States well beyond 1990.

To map our future intelligently, we must find out how much of our energy needs can be met from domestic oil and gas resources. Projections by DOE indicate that this country can continue to produce crude oil at a rate of about 8 million barrels a day until the year 2000. But to reach that goal, a great deal of work must be done -- and quickly. At current rates of production, three-fourths or more of today's proved reserves will have been depleted by the turn of the century. Thus, most of the oil and gas we will need 17 years from now has not yet been discovered.

What Happened During the 1970s

During the 1970s, the United States used up its proved reserves of oil and natural gas much more rapidly than new supplies were discovered. Those record levels of consumption caused reserves to decline sharply. To fill the gap between domestic production and domestic consumption, this country became increasingly dependent on foreign oil. By 1977, the United States was importing 8.8 million barrels of crude oil

and petroleum products a day.³ That represented 48 percent of our oil supply.

Much of the imported oil came from politically unstable regions of the world. Americans realized the risks involved in such heavy dependence on at least two occasions during the 1970s -- the Arab oil embargo of 1973-1974 and the cutoff of oil shipments from Iran following that country's revolution in the latter part of the decade. In both instances, relatively small reductions in the amount of imported oil available to Americans, coupled with government allocation and price controls, led to serious shortages in some parts of the country.

Furthermore, heavy dependence on imported oil in the United States and other countries made it possible for the Organization of Petroleum Exporting Countries (OPEC) to raise world oil prices from \$1.80 a barrel in 1970 to \$34 a barrel or more in 1981. The situation also allowed some members of that group to use oil as a political weapon.

Changes in the 1980s

By early 1983, however, this country's oil supply situation had improved and the nation's energy security had been strengthened. These were some of the significant developments of the early 1980s:

- Oil decontrol in 1981 stimulated record amounts of exploration and drilling in the United States.

- A major new field began producing oil from Alaska's North Slope.

- Important discoveries were announced off the coast of California, in the Gulf of Mexico, in the Rocky Mountain area and elsewhere.

- The sharp declines in proved reserves leveled off.

- U.S. oil consumption dropped from a peak of 18.8 million barrels a day in 1978 to a little more than 15 million barrels a day in 1982.⁴

- Oil imports dropped from a daily average of 8.8 million barrels in 1977 to 4.9 million barrels a day in 1982⁵ and about 3.9 million barrels a day in the first five months of 1983, excluding crude oil imported by the government for storage in the Strategic Petroleum Reserve.⁶

- The United States diversified the sources from which it purchased oil. In 1982, Mexico was the leading supplier of oil to this country, followed by Saudi Arabia, Nigeria, Canada, the

United Kingdom, Venezuela, the Virgin Islands, Indonesia, the Netherlands Antilles and Algeria, in that order.⁷

- Worldwide oil prices began to come down because of reduced demand.

Dependence on Foreign Oil Declines

As a result of these trends, the nation's dependence on imported oil dropped to 33 percent in 1982⁸ and to 26 percent in the first five months of 1983.⁹

Although part of the decline in oil consumption can be attributed to the economic recession, a larger portion is believed to be the result of permanent changes in consumption patterns, including greater efficiencies in space heating, transportation and industrial production.

Despite these improvements, Americans have no reason to be complacent about their future energy supplies. Because of the problems affecting the increased use of this country's abundant coal resources and the problems retarding the development of nuclear power, solar energy, synthetic fuels and other supplemental energy sources, most analysts believe oil and gas will continue to play vital roles in the overall energy picture for years to come. And much of the oil and gas we will be using 10 or 15 years from now still must be discovered and developed.

Looking to the Future

No one knows precisely how much oil and natural gas this country will be capable of producing in 1990. The answer to that question will depend on the level of investment directed toward finding new supplies and keeping old fields producing longer, and on the success of those efforts.

Many factors will affect the levels of activity in the petroleum industry. Among the greatest needs are an adequate flow of investment capital, reasonable access to potentially productive areas on government and private lands, tax policies that encourage the development of energy resources, an end to federal price controls on natural gas and a streamlining of the enormously complex procedures required to gain permission to find, develop, produce, process and transport oil and natural gas.

To help ensure the future, the nation should eliminate unnecessary delays in determining what its energy resources are and should increase its capacity to produce oil and gas as rapidly as possible. A reasonable goal for 1990 would be to hold oil import levels close to current levels or to reduce them even further if possible.

As discussed earlier, many projections were studied for this paper. Taken together, they offer a composite view of 1990 energy production.

Production of oil and natural gas liquids in 1982 averaged slightly more than 10.2 million barrels a day.¹⁰ The studies and projections reviewed for this paper (see base case, page 18) show a 1990 range of 7.9 million to 9.7 million barrels daily.

U.S. production of dry natural gas in 1982 was more than 17.5 trillion cubic feet -- the energy equivalent of 8.5 million barrels a day of crude oil.¹¹ The projections studied (see base case, page 18) show a range of 14.6 trillion to 19 trillion cubic feet a year (the equivalent of 7.1 million to 9.2 million barrels a day of oil) by 1990.

Thus, for both oil and natural gas, some of the studies anticipate declines in production over the coming decade.

Those projections, of course, are based essentially on what the analysts believe is likely to happen, not on what inevitably will happen.

If we as a nation choose to make efficient use of our potential petroleum resources, within this decade we can stabilize oil and natural gas production near today's levels. As indicated in Chapter I, the accelerated case suggests the possible 1990 production of some 9 million to 10 million barrels a day of crude oil and natural gas liquids and some 16.5 trillion to 18.5 trillion cubic feet of natural gas a year (the equivalent of about 8 million to 9 million barrels a day of oil).

This point needs emphasis: To make the United States as energy secure as possible by 1990, efforts must be made now to find and produce more oil and natural gas. Enormous exploratory efforts and unprecedented investments will be required to reach even the lowest projected figures.

Under current conditions, lead times between initial exploration and first production in some frontier areas are estimated to be 8 to 11 years. Thus, rapid exploration and development of the nation's oil and gas resource potential will be essential to help offset declining production in older fields. The rate of growth in oil and gas production will depend largely on governmental leasing and regulatory policies. In the accelerated case estimates of this paper, it is assumed that those government policies will be improved.

Seven basic facts about oil and gas will be addressed in this chapter:

1. More domestic oil and gas can be found and produced.

2. Major future discovery areas are the western states, Alaska and offshore.
3. Government controls access to promising areas.
4. Government affects petroleum development through environmental laws and regulations.
5. Decontrol of oil brightened the U.S. energy picture.
6. Decontrol of all natural gas can provide many benefits to Americans.
7. Petroleum companies are investing heavily to find more crude oil and natural gas.

* * * * *

1. More Domestic Oil and Gas Can Be Found and Produced.

It was 1970 when industry statistics, as reported by the American Petroleum Institute and the American Gas Association, first reflected the oil and gas discoveries in the Prudhoe Bay field on Alaska's North Slope. Oil and gas reserves declined each year throughout the rest of the 1970s.

Between the end of 1970 and the end of 1979 this country's proved oil reserves dropped by nearly 12 billion barrels, while natural gas proved reserves declined nearly 96 trillion cubic feet -- the energy equivalent of almost 17 billion barrels of oil.¹² Thus, the nation liquidated about one-third of its proved oil and gas reserves within one decade.

Throughout most of the 1970s, this country used up its proved oil reserves almost twice as fast as new supplies were being found. The United States withdrew a yearly average of 3 billion barrels of oil from proved reserves while replacing them with a yearly average of only 1.6 billion barrels of newly found petroleum. In the same period, natural gas production in the lower 48 states was nearly twice the amount of new reserves added.

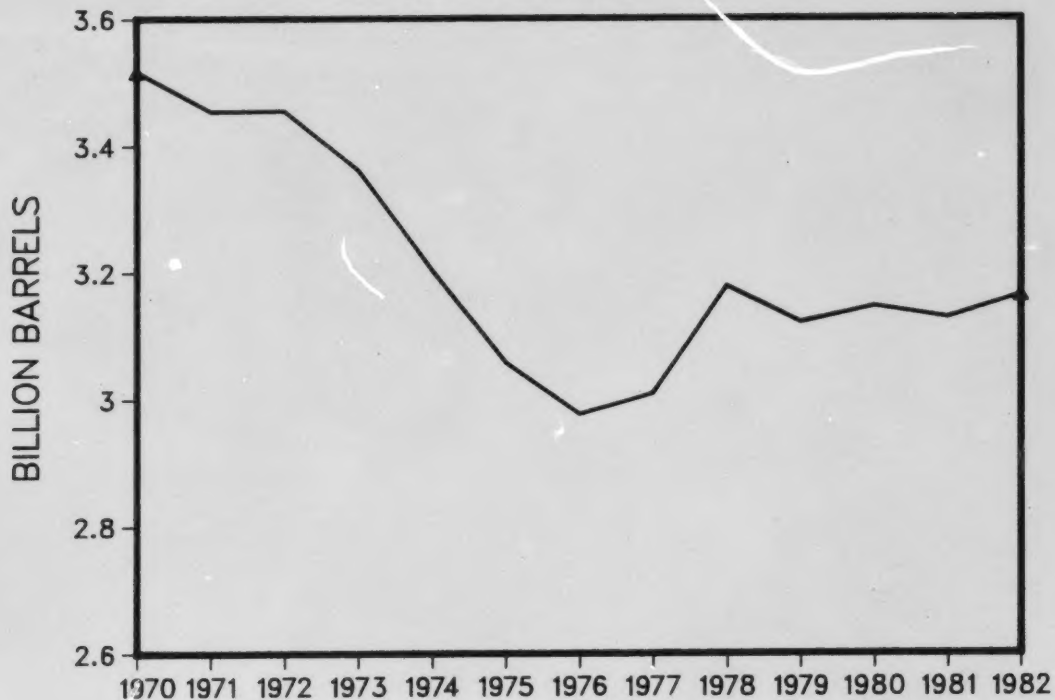
Domestic production of oil and natural gas liquids peaked at 11.3 million barrels a day in 1970 and declined to about 10 million barrels a day in 1979. Oil production in the lower 48 states declined by a yearly average of about 300,000 barrels a day. Production of dry natural gas peaked at about 10.5 million barrels a day of oil equivalent in 1973 and declined to about 9.5 million barrels a day of oil equivalent in 1979.¹³ During those years, domestic oil and interstate natural gas were under federal price controls.

In the early 1980s, the United States has begun to reverse those downward trends in reserves and production. With the removal of oil price controls, oil production already has taken an upward turn. Similarly, natural gas production could increase if government restrictions on the pricing and use of gas were removed. Meanwhile, the most recent government studies show that proved reserves are no longer declining steeply. The estimates at the end of 1981 showed increases for natural gas and natural gas liquids and only a small decrease for crude oil reserves.

Trends in Oil Production

U.S. production of crude oil and lease condensate reached a peak of 3.5 billion barrels a year in 1970. A decline began in 1971 and continued through 1976, when the annual total was less than 3 billion barrels. In the late 1970s, oil production began to recover as a result of higher oil prices, increased drilling activity and the nation's determination to reduce its dependence on imported oil. From 1978 through 1982, the annual figure fluctuated in a range between 3.1 billion and 3.2 billion barrels. (See graph, "Petroleum Production in the United States.")

PETROLEUM PRODUCTION IN THE UNITED STATES



SOURCE: SEE APPENDIX

The Department of Energy (DOE) reported these daily average production figures for crude oil and lease condensate (hydrocarbon gases that emerge from wells in liquid form):

1979 -- 8,552,000 barrels a day;

1980 -- 8,597,000 barrels a day;

1981 -- 8,572,000 barrels a day;

1982 -- 8,671,000 barrels a day.¹⁴

Domestic production of oil and condensate continued to increase slightly during early 1983. The American Petroleum Institute (API) estimated that U.S. oil production during the first five months of 1983 averaged 8,676,000 barrels a day. That was a gain of 21,000 barrels a day over the figure for the comparable months of 1982.¹⁵

Oil from the Kuparuk field on Alaska's North Slope, which began flowing southward in December 1981, has accounted for most of the increase since that time. By the spring of 1983, the Kuparuk field was producing about 100,000 barrels of oil a day. After declining since 1972, oil production in the lower 48 states has begun to increase.

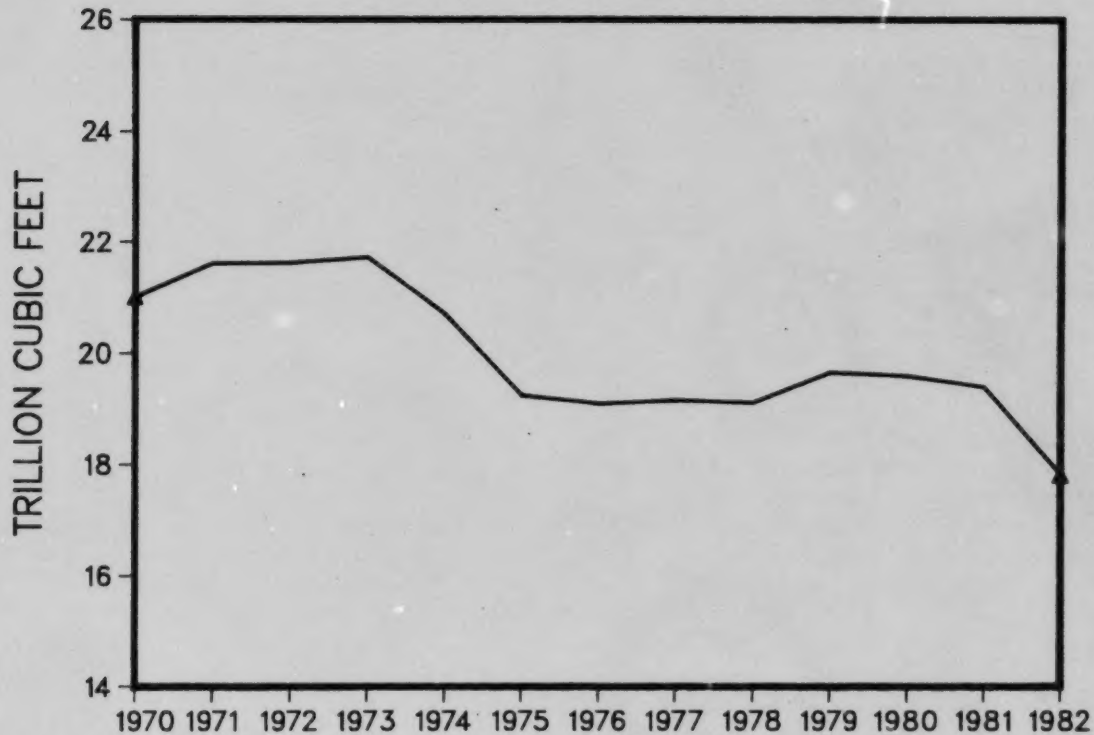
The stabilizing of lower-48 oil production is especially significant when compared with the annual average decline of 300,000 barrels a day from those states during most of the 1970s. If that downward slide had not been halted, oil production in the lower 48 states by early 1983 would have been about a million barrels a day lower than it actually was.¹⁶

Production of Gas and Gas Liquids

DOE reports show that annual net production of dry natural gas in the United States increased from 21 trillion cubic feet (tcf) in 1970 to a record high of 21.7 tcf in 1973. A downward trend began in 1974 and, with minor fluctuations, continued through 1982. For the four most recent years, the figures were 19.7 tcf in 1979, 19.6 tcf in 1980, 19.4 tcf in 1981 and 17.8 tcf in 1982.¹⁷ The 1982 figure was the lowest since 1967. (See graph, "Dry Natural Gas Production in the United States.")

Preliminary DOE figures for the first quarter of 1983 indicate a drop of about 11 percent in gas production from early 1982.

DRY NATURAL GAS PRODUCTION IN THE UNITED STATES



SOURCE: SEE APPENDIX

DOE reported these figures for extraction of natural gas liquids at gas processing plants:

1979 -- 1,584,000 barrels a day;

1980 -- 1,573,000 barrels a day;

1981 -- 1,609,000 barrels a day;

1982 -- 1,554,000 barrels a day.¹⁸

For the first five months of 1983, API estimated daily production of natural gas liquids at 1,594,000 barrels a day -- up 44,000 barrels a day, or nearly 3 percent, from the comparable months of 1982.¹⁹

Natural gas liquids are those portions of reservoir gas that are liquefied at the surface in lease separators, field facilities or gas processing plants. They include ethane, propane, butanes, pentanes, natural gasoline and lease/plant condensate. Removing these components and certain impurities such as sulfur leaves a clean-burning dry gas that meets pipeline quality standards.

The liquids thus removed from the gas stream represent about 3.5 percent of all the energy produced in the United States. Some gas liquids are processed further and sold as separate products. Others are blended with crude oil to provide raw materials for the manufacture of refined petroleum products and petrochemicals.

Productive Capacity Is Not the Problem

Many industry analysts and gas producers have pointed out that the most recent decline in natural gas production is not due to a lack of capacity to produce. Indeed, within the past year or two some producers and some pipelines have been unable to sell all of the gas available to them at the prices prevailing in the government-regulated market. And producer prices for some categories of gas have fallen as the producers attempted to keep selling their gas.

Analysts say the demand for natural gas has been depressed by rising prices, the weakness of the nation's economy, government restrictions on the industrial use of natural gas, switching by some industrial plants to other fuels whose prices have declined recently and market distortions caused by federal controls on wellhead prices of natural gas.

Consumption of natural gas in the United States in 1982 was 8 percent below the 1981 level. The largest drop occurred in the industrial sector, where 1982 gas usage was down 16 percent from the previous year.²⁰ The decline continued in early 1983.

The oversupply of natural gas, however, is expected to be temporary. Reserves in current producing areas are being depleted rapidly, and the demand is expected to increase as the economy recovers from the recession. Therefore, it should not be assumed that the United States has more than enough natural gas available to meet its long-term needs. Intensive exploration and drilling will be needed to maintain adequate supplies in the years ahead, especially if transportation facilities for the gas reserves on Alaska's North Slope cannot be completed within the next few years.

Nicholas J. Bush, president of the Natural Gas Supply Association, called this matter to the attention of a congressional

committee on September 20, 1982. Citing estimates by gas pipeline companies and by the consulting firm of Foster Associates, he said:

Between 1981 and 1986 supply from presently connected reserves will decline by 49 percent, and between 1981 and 1991 by 76 percent. Specifically, interstate pipelines have continually expressed concern about the expected decline in natural gas deliverability from the major producing region of the Texas-Louisiana Gulf Coast, where large volumes of gas reserves are being depleted at very rapid rates. Data supplied by the pipelines for this region indicate an expected turning point in deliverability within the next three to five years, with a steep decline in gas production thereafter.²¹

The Natural Gas Supply Association, the American Petroleum Institute and the Independent Petroleum Association of America, which speak for most of the nation's natural gas producers, have urged that federal wellhead price controls on all categories of domestic gas be phased out. They also have urged the elimination of "incremental pricing" regulations and end-use restrictions. They believe that decontrolling natural gas prices would stimulate the discovery and production of gas and encourage its efficient use, thus eliminating the need for any kind of governmentally imposed price or allocation plan. A number of other producer, user and business and industrial organizations support that position.

Proved Reserves Begin Leveling Off

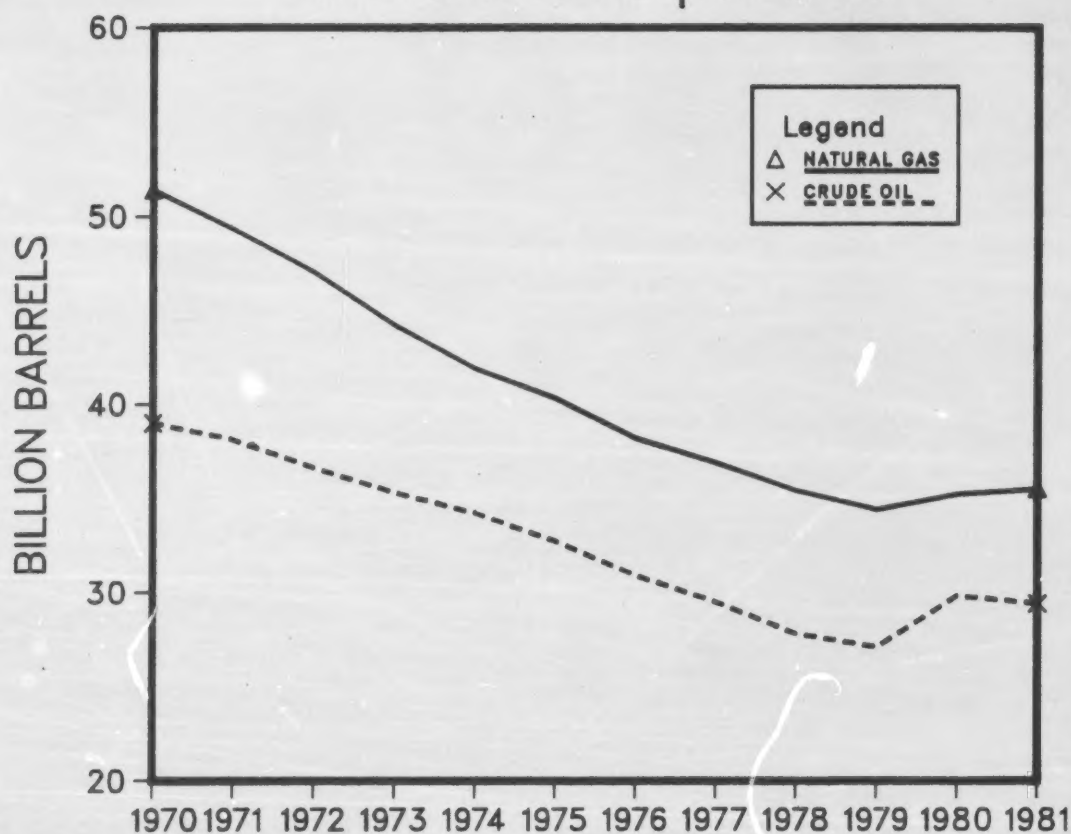
After declining sharply throughout the 1970s, the nation's proved reserves of crude oil and natural gas may have begun to stabilize. (See graph, "Proved Reserves of Oil and Gas.")

Proved reserves represent estimates of already discovered oil and natural gas believed to be recoverable under current economic and operating conditions. As reservoirs are developed, more data become available, enabling the estimates to become increasingly accurate. Initial estimates are revised either upward or downward, depending upon what is learned as work progresses.

Here are the Department of Energy's estimates of proved reserves at the end of the years indicated (figures for 1982 will be published in the autumn of 1983):²²

	<u>Crude Oil</u>	<u>Dry Natural Gas</u>	<u>Natural Gas Liquids</u>
<u>Year</u>	(millions of bbls.)	(billions of cu. ft.)	(millions of bbls.)
1977	31,780	207,413	No estimate
1978	31,355	208,033	6,772
1979	29,810	200,997	6,615
1980	29,805	199,021	6,728
1981	29,426	201,730	7,068

PROVED RESERVES OF OIL AND GAS in crude oil equivalent



SOURCE: SEE APPENDIX

According to these figures:

- Crude oil proved reserves dropped nearly 5 percent in 1979, then began to level off. They declined less than 2/100ths of 1 percent in 1980 and 1.3 percent in 1981.

- Natural gas proved reserves decreased more than 3 percent in 1979 but dropped only 1 percent in 1980. Estimates increased 1.4 percent in 1981, due largely to revisions in figures published in prior years.

- Proved reserves of natural gas liquids dropped more than 2 percent in 1979 but showed increases of 1.7 percent in 1980 and slightly over 5 percent in 1981.

Thus, total reserves of liquid hydrocarbons (crude oil and natural gas liquids) remained virtually constant during 1981. The DOE report also listed nearly 1.6 billion barrels of "indicated additional crude oil" that may become economically recoverable from existing reservoirs if and when improved recovery techniques are successfully applied.²³ These supplies are not currently shown as proved reserves because of uncertainty over their economic recoverability.

DOE figures show that nine producing states recorded increases in both crude oil and natural gas proved reserves during 1981. They were Alabama, Arkansas, Kansas, Louisiana, Mississippi, Montana, New Mexico, North Dakota and Oklahoma. In addition, there were significant increases in oil reserves in Illinois and Michigan and gains in natural gas reserves in California, Colorado, Kentucky, New York, Pennsylvania, Texas, Utah and Wyoming.

The relative stability of proved oil and gas reserves in 1980 and 1981, when compared with the declines of the past decade, resulted in large part from the increased drilling activity of recent years and increased investment in keeping old fields alive. The removal of oil price controls and some increases in natural gas prices provided the impetus for much of this activity. The decline in natural gas consumption also was a factor in stabilizing gas reserves.

What Reserves Figures Mean

The DOE emphasizes that reserves figures represent only estimates -- not precise inventories. Nevertheless, proved reserves are the only supplies the nation can depend upon at any given time. They are extremely important in assessing national security, assuring continuity of supply and planning for the future.

It takes years to find new oil and gas fields, to develop them and to build transportation systems to deliver the

products to market. Also, the physical characteristics of oil and gas fields require that supplies be produced over a number of years to achieve maximum recovery. Therefore, it is essential to maintain at least a few years of "cushion" in the form of proved reserves. As 1982 began, U.S. proved reserves of oil and natural gas were equal to about 10 years of production at current levels.

However, that does not mean that this country will run out of oil and gas in 10 years. Proved reserves estimates do not represent this country's total potential ability to find and produce oil and natural gas.

The United States can continue finding and producing oil and gas by:

- exploring onshore and offshore frontier areas which have never been tested with the drill;
- drilling deeper in areas that are already productive;
- re-examining older, mature producing areas in such states as Pennsylvania, New York, Ohio and West Virginia;
- using more sophisticated technology to find petroleum; and
- applying the most efficient recovery methods available to extract as much oil and gas as possible from the earth. The United States has an estimated 300 billion barrels of known oil resources that have not been economic to produce. If even 10 percent of that oil can be produced through enhanced recovery methods now being developed, today's proved oil reserves will be doubled.

Prophets of Gloom Were Wrong

Over the past century there have been many gloomy predictions about this country's petroleum potential:²⁴

- In the 1880s and 1890s a government bureau said there was little or no chance of finding oil in California, Kansas or Texas. Today, they are among the leading oil-producing states.

- A 1920 government report said the United States had almost reached its peak in oil production, which was then 443 million barrels a year. In later years, the nation's oil output climbed to more than 3.5 billion barrels a year before declining to current levels of around 3 billion barrels annually.

- In 1939 a government official said America's oil supplies would last only 13 years.

- In 1949 a federal official announced that the end of United States oil supplies was almost in sight.

- Until 1974, many people said oil and gas would never be found in the Western Overthrust Belt. But large amounts of oil and gas have been found there, and it is one of the most actively explored areas in the United States.

There have always been discouraging predictions. But drillers have kept on working and hoping. As a result, today 33 of the 50 states produce oil, natural gas, or both.

Analysts Agree: Potential Is Great

Studies by government agencies, scientific organizations, universities and oil companies have concluded that this country has the potential to produce large amounts of oil and gas for many years to come.

Those studies of the undiscovered recoverable oil and gas resources of this country were made by different persons at various times during the past few years. Because they used varying geological data and production histories and differing assumptions concerning economics and technology, they reached conclusions that vary from one study to another.

Dr. Charles D. Masters, who was then chief of the Office of Energy Resources in the U.S. Geological Survey (USGS), reviewed several such studies in a speech in 1979.²⁵ He said that although the estimates vary in detail, they indicate that at least for the next 30 to 50 years, resource potential will not be a limiting factor in sustaining U.S. oil and gas production.

The limiting factor, Dr. Masters said, will be the rate at which this country can find those supplies and convert them from potential to proved reserves. Many geologists share that view.

How much of this oil and gas will be found and produced -- and how soon -- will depend on many factors, including pricing, incentives for investment, technological progress, access to promising new areas to explore, environmental restrictions and the overall political and economic climate.

The differences of opinion reflected in the varying estimates of this country's oil and natural gas potential serve a useful purpose. They emphasize the need to accelerate leasing and drilling of promising prospects so that the nation can base its plans on facts rather than guesses.

How Much Can We Produce?

The U.S. Geological Survey (USGS) published its most recent detailed study of undiscovered recoverable oil and gas resources in the spring of 1982.²⁶ Using a range of numbers based on probability levels, Geological Survey Circular 860 concluded that as of mid-1980, the nation's undiscovered oil resources were between a low estimate of 64 billion barrels and a high estimate of 105 billion barrels, with a mean of about 83 billion barrels.

For natural gas, the estimates ranged from a low of 475 trillion cubic feet to a high of 739 trillion cubic feet, with a mean of 594 trillion cubic feet (the energy equivalent of about 105 billion barrels of oil).

The mean figure for natural gas liquids was nearly 18 billion barrels.

Even those huge figures, however, do not represent this country's total potential production.

In addition to estimating current proved reserves and undiscovered resources, the federal government also publishes estimates of how much oil and gas may be found through extensions of existing fields, opening new productive zones and revisions of prior estimates. It also calculates how much more oil may become producible when improved recovery techniques, such as fluid injection, are applied to known fields.

When all those categories are added up, government studies estimate that, with sufficient effort, this country's future energy production could include:

- 139 billion barrels of crude oil;
- 25 billion barrels of natural gas liquids; and
- more than 970 trillion cubic feet of natural gas (the energy equivalent of more than 170 billion barrels of oil).²⁷

To put those figures into perspective, that would be:

- about 44 times more oil, 44 times more natural gas liquids and 55 times more dry natural gas than the United States produced in 1982; and
- about 4 percent more oil and 53 percent more natural gas than this country produced from the beginning of the petroleum industry through 1982.

USGS Circular 860 superseded Circular 725, which had been published in 1975. The new appraisal showed a 22 percent in-

crease in the mean estimate of undiscovered natural gas resources, compared with the 1975 study. The mean figure for crude oil remained about the same.

In contrast to the earlier study, Circular 860 extended its scope to include offshore waters to a depth of 2,500 meters, instead of stopping at the 200-meter depth. This change added about 400,000 square miles of submerged land to the area being considered. The USGS said advances in technology are making deeper waters more accessible to possible exploration and development.

In Circular 860, the USGS commented:

About 66 percent of the undiscovered oil and 72 percent of the undiscovered gas is estimated to occur onshore. The region with the greatest onshore oil potential is the Colorado Plateau and Basin and Range, which includes the Wyoming-Utah-Idaho thrust belt. Offshore oil potential is greatest for Alaska, followed by the Gulf of Mexico and the Atlantic Coast. For gas, the mean values indicate that the Gulf Coast has the greatest potential onshore and that the Gulf of Mexico has the greatest potential offshore.²⁸

Some petroleum company analysts believe that offshore areas and Alaska will play even more important roles in future production than the government estimates suggest. In such areas, however, costs are so high that discoveries must be large in order to justify the investments required to develop them and bring them to market.

But even this is only part of the story. The government's estimates of proved reserves and undiscovered recoverable conventional oil and gas resources exclude several energy sources with enormous potential.

For example, the USGS estimates of potential production do not include vast amounts of oil and gas that are known to exist, but which cannot be produced now -- either because the necessary technology has not been developed or because production costs would exceed the market value of the products.

In 1975 the USGS estimated that this country's resources might include as much as 250 billion barrels of oil and 200 trillion cubic feet of natural gas that were not currently economically producible. As technology continues to advance and conditions change, it may become physically possible and economically feasible to produce significant amounts of that oil and gas.

Circular 860 also did not estimate the amount of energy that may eventually be produced from heavy oil deposits, tar sands, oil shales, gas in low-permeability "tight" reservoirs, gas locked in coal seams, gas in geopressured shales and brines, or gas in natural gas hydrates (ice-like mixtures of methane and water, sometimes found in permafrost or in sediments beneath the ocean floor).

Devonian shales that lie beneath 160,000 square miles of the Appalachian basin also were not included in USGS estimates of potential production. Another USGS study, published in 1982, estimated that enormous amounts of gas may be trapped in those rocks, but the study did not try to estimate how much of that gas may ultimately become producible. The USGS estimates of gas in place in the Devonian shales ranged from 577 trillion cubic feet to 1,131 trillion cubic feet, with a mean estimate of 844 trillion cubic feet (the equivalent of 149 billion barrels of oil).²⁹ Some of those rocks lie near the surface, while others are as much as 12,000 feet below sea level. Many of the shale formations are characterized by low permeability and small porosity, which make it difficult to extract the gas.

A New Industry Estimate

The most recent study by the Potential Gas Committee, funded by the American Gas Association, estimates that more than half of the natural gas resources originally existing in the United States have not yet been discovered. The biennial report of the committee indicates that as of December 31, 1982, this country had the potential to find and produce about 876 trillion cubic feet of natural gas in the future, in addition to current proved reserves of more than 201 trillion cubic feet.³⁰ The undiscovered gas is the equivalent of 154 billion barrels of crude oil.

The Potential Gas Committee's estimate covers only those resources believed to be discoverable and producible by the use of conventional methods and developing technology. The figures represent potential resources both onshore and offshore to a water depth of 1,000 meters. The total includes gas that may be found through extensions of existing fields, new deposits that may be found in areas that are already producing and resources that may be discovered in areas where no gas has been produced.

2. Major Future Discovery Areas Are the Western States, Alaska and Offshore.

The vast majority of the untested areas believed to have oil and gas potential are controlled by the federal government, which has not made the great bulk of those lands available for exploration and drilling.

More Than a Century of Production

The nation's first oil well was completed at Titusville, Pennsylvania, in 1859. It found oil at a depth of only 69 feet.

Since then, more than 2.7 million wells have been drilled in the United States and its offshore waters in search of oil and gas.³¹ In recent years some wells have probed as deep as 30,000 feet -- more than 5 miles.

Historically, most oil and gas drilling has been done on privately owned land. Oilmen negotiate leases with landowners and usually pay them a cash bonus, plus a share of the value of any oil or gas produced.

Currently, about 523 million acres of onshore land are estimated to be under lease for oil and gas operations in the United States. So far, only 73 million onshore acres have proved to be capable of producing oil or natural gas.³²

About three-fourths of the land under lease is owned either privately or by state and local governments or by Indian tribes. Wells on those leases provided nearly 85 percent of the oil and 68 percent of the natural gas produced in this country in 1982.

Where the Best Chances Are

Still largely unexplored and untested, however, are hundreds of millions of potentially productive acres owned by the federal government. The onshore government lands are concentrated mainly in the western states and Alaska. Offshore, the federally controlled waters of the Outer Continental Shelf (OCS) lie beyond the limits of state jurisdiction.

Studies by government agencies, industry analysts and academic scholars agree that onshore and offshore government lands have the potential to supply major portions of this country's oil and natural gas needs in the future.

The National Energy Policy Plan, a report submitted to the Congress by the Department of Energy in July 1981, estimated that onshore and offshore government lands contain 85 percent of the nation's oil, 40 percent of its natural gas and large percentages of other energy resources.³³ The same report pointed out that "except for rough estimates, we do not know the full extent of our mineral values, our oil and gas reserves, our oil shale, tar sands, and geothermal capabilities."

Geological Survey Circular 860 estimated that federal waters contain 95 percent of the undiscovered oil and gas likely to be found off the lower 48 states.³⁴ Onshore government lands in

the lower 48 states are estimated to contain 30 percent of the undiscovered oil and 25 percent of the undiscovered gas likely to be found in those states. The USGS did not provide similar estimates for Alaska because scheduled transfers of federal lands to the Alaskan state government and native groups had not been completed.

Some oil company analysts believe the estimates of potential federal oil and gas ownership in Circular 860 may be too conservative. Some of them believe that as much as 70 percent of the remaining oil and gas to be found in the United States may lie beneath onshore and offshore government lands.³⁵

3. Government Controls Access to Promising Areas.

The federal government is, by far, the largest landowner in the United States. Some 70 federal departments, agencies, bureaus and other units own federal lands.³⁶ And other agencies -- such as the Environmental Protection Agency -- exercise considerable influence over the way federal lands are used.

Onshore

The General Services Administration recently reported that the federal government owned nearly 720 million acres of onshore land at the end of fiscal year 1980. That represented nearly one-third of the nation's total land area of 2.27 billion acres.³⁷

That federally owned land was distributed as follows:

- 307.4 million acres in Alaska,
- 359.4 million acres in 11 western states, and
- 52.7 million acres in other states.

In addition to land owned outright, the government retains the subsurface mineral rights to 66 million acres of land in various parts of the country.³⁸ That is an area larger than the states of Indiana, Ohio and West Virginia combined.

Thus, the federal government either owns or controls the mineral rights on onshore lands nearly five times the size of Texas or eight times the size of California.

Alaska contains more federally owned land than any other state. The latest tabulation shows 84 percent of Alaska owned by the federal government in fiscal 1980. When all scheduled transfers to the state government and native groups have been completed, the federal government will still own about 60 percent of Alaska's total land surface -- an area seven times larger than the state of New York.

Many of this country's best prospects for major new oil and natural gas discoveries are believed to lie within the 11-state western region that includes Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington and Wyoming. Of the 753 million acres of land in these states, the federal government owns 48 percent. The U.S. Geological Survey estimates that this region may contain more than half of the nation's undiscovered onshore oil and 35 percent of the undiscovered onshore natural gas.³⁹

Although important discoveries have been made recently in areas such as the Western Overthrust Belt, exploratory drilling has never been permitted in many western areas that are believed to offer great potential for oil and gas production.

As of December 31, 1982, the Interior Department reported that 162 million acres of onshore government land were under lease for oil and gas exploration and development.⁴⁰ Although that was an all-time high, the figure represents only 23 percent of the total onshore area owned by the government.

In 1982, wells on onshore government lands produced nearly 150 million barrels of crude oil and condensate and more than 1.1 trillion cubic feet of natural gas. Those quantities represented 5.4 percent of the oil and 6.9 percent of the natural gas produced in this country.⁴¹

Government studies have estimated that nearly 261 million acres of onshore government land in the lower 48 states offer the possibility for the discovery of oil and gas.⁴² That represents about 63 percent of the federally owned lands in those states. But the only way to be certain about the existence and extent of those resources is by drilling. U.S. oil and gas producers are confident that exploration in selected areas, with adequate environmental safeguards, can add significantly to the nation's energy supplies. And because it takes years to find and develop new supplies, they urge that as little time as possible be lost in gaining access to areas with the greatest potential.

Offshore

There are about one billion acres of submerged lands off the coasts of the United States out to a water depth of 2,500 meters.⁴³

The coastal states control about 33 million acres adjacent to their shorelines. Most coastal states exercise jurisdiction over waters extending outward three statute miles from land, but the rules are different for Texas and the west coast of Florida because of differences in historic treaties. State control in those waters extends outward three marine leagues -- about 10.4 miles.

The federal government controls about 966 million offshore acres. Of that total, 528 million acres are between the outer limits of state jurisdiction and the 200-meter water depth. The other 438 million acres are in deeper waters.

USGS estimates of the undiscovered recoverable crude oil beneath this country's offshore waters from the shore out to a depth of 2,500 meters range between 17 billion and 44 billion barrels, with a mean of 28 billion barrels.⁴⁴

The mean estimate of undiscovered natural gas liquids beneath U.S. offshore waters is 4.7 billion barrels.

The USGS estimates for undiscovered offshore natural gas range between 117 trillion and 231 trillion cubic feet, with a mean of 167 trillion cubic feet (the energy equivalent of 29 billion barrels of oil).

By comparison, proved reserves for the entire United States, onshore and offshore, as 1982 began, were estimated at 29.4 billion barrels of oil, 7.1 billion barrels of natural gas liquids and nearly 202 trillion cubic feet of natural gas (the energy equivalent of 35.5 billion barrels of oil).⁴⁵ Thus, according to midrange estimates by the USGS, the nation's offshore waters are believed to have the potential to increase today's proved oil and gas reserves by 86 percent.

The federal government sold leases on 24.4 million offshore acres for oil and gas operations from the beginning of the program in 1954 through April 1983.⁴⁶ That represented 4.6 percent of the acreage out to a water depth of 200 meters and about 2.5 percent of the entire federal offshore area. Many of the older leases have expired and about 16 older fields have been depleted. As of December 31, 1982, about 12.6 million federal offshore acres were still under lease.⁴⁷ That represented only 1.3 percent of the total federal offshore waters.

U.S. offshore oil production increased steadily from the early 1950s through 1971, reaching a peak of 615 million barrels in the latter year. Then -- during the years when oil prices were controlled by the federal government and offshore leasing opportunities were limited -- production went into a decline that lasted through 1980. By the end of that period, the annual rate of crude oil and condensate production from state and federal offshore leases had dropped to 374 million barrels -- 39 percent below the 1971 peak.⁴⁸

Interior Department reports indicate that, with the removal of oil price controls and the ensuing boom in drilling, total offshore oil and condensate production in 1981 increased by 8.4 million barrels, or 2 percent, over the previous year. This was the first year-to-year increase in offshore oil production from federal leases since 1971.⁴⁹

Natural gas production from federal and state waters developed later than oil production. Gas from offshore wells increased from about 85 billion cubic feet in 1954 to 5.5 trillion cubic feet in 1981. The 1981 figure represented an increase of nearly 3 percent over the previous year.⁵⁰

The upward trend in offshore gas production since the 1950s reflected the discovery and development of major gas deposits in the Gulf of Mexico. It also reflected a growing demand for natural gas, a rising level of prices, the completion of additional production and pipeline facilities to move offshore gas to shore and the expansion of the nation's gas distribution system.

The first "offshore" well was drilled in 1894 from a wooden pier extending from the shore at Summerland, California, near Santa Barbara.⁵¹ About 400 shallow wells were drilled from piers in the vicinity in the late 1800s. For many years, offshore operations were limited to shallow water, but eventually the technology was developed to extend the search far out to sea.

The first well drilled in open water was completed one mile off the coast of Louisiana in 1938. Nearly a decade later, in 1947, the world's first producing well out of sight of land was completed, in 20 feet of water, 12 miles from the Louisiana coast.⁵² The first offshore platforms in California waters were installed in the 1950s.

The offshore petroleum industry has made tremendous progress since those days, as the search for oil and gas beneath the sea has spread throughout the world. In the Gulf of Mexico, a platform is producing oil and natural gas in water 1,025 feet deep -- the deepest water in which production has been achieved anywhere in the world. In the Mediterranean Sea, a French company drilled an unproductive well in 5,624 feet of water during 1982. Off the U.S. Atlantic coast, oil companies are beginning a new round of exploration in water that may be as deep as 7,500 feet in the Baltimore and Wilmington Canyons. Preliminary designs have been drawn for rigs that could explore in 10,000 feet of water. And, as part of the National Science Foundation's Ocean Margin Drilling Program, planning is under way to equip a drilling vessel to operate in 13,000 feet of water.⁵³

By the end of 1982, a total of 29,574 wells had been drilled in United States coastal waters -- most of them in the Gulf of Mexico. About 29 percent were in waters controlled by state governments and 71 percent on the federally controlled Outer Continental Shelf (OCS). About 43 percent were completed as oil wells and 17 percent as gas wells. The other 40 percent were dry holes.⁵⁴

Production from federal offshore leases in 1982, as reported by the U.S. Department of Interior, totaled 321 million barrels

of crude oil and condensate and nearly 4.7 trillion cubic feet of natural gas. Compared with 1981, those figures represented an increase of 12 percent in liquid hydrocarbon production and a decrease of more than 3 percent in gas production.⁵⁵ Wells on federal offshore leases provided about 10 percent of all the crude oil and condensate and more than 25 percent of the natural gas produced in the United States in 1982.⁵⁶

From 1954 through 1982, cumulative production from wells on the federal OCS amounted to 6 billion barrels of oil and 58 trillion cubic feet of natural gas.

From the beginning of offshore operations through 1981, wells in state and federal waters off the coasts of Louisiana and Texas accounted for 71 percent of this country's offshore oil production and nearly 98 percent of offshore natural gas output. California waters accounted for 21 percent of the offshore oil production and 1 percent of the offshore gas. Wells in state waters off Alaska accounted for 8 percent of the nation's total offshore oil production and more than 1 percent of the offshore gas produced. As of mid-1983, no oil or gas had been produced from federal leases off Alaska's coasts.⁵⁷

At the end of 1981, a total of 489 oil and natural gas fields were active in the federally controlled portion of the Gulf of Mexico -- an increase of 23 fields over the figures reported by the Interior Department a year earlier.⁵⁸ Wells on federal and state leases in the Gulf of Mexico produced a cumulative total of 6.7 billion barrels of oil and 65.5 trillion cubic feet of natural gas from the beginning of offshore operations through 1981. That left an estimated 3 billion barrels of oil and 40 trillion cubic feet of natural gas remaining to be produced from proved reserves in that area. In addition, the mean estimates of the U.S. Geological Survey indicate that the Gulf of Mexico may contain undiscovered recoverable resources amounting to about 6.6 billion barrels of oil and 72 trillion cubic feet of natural gas.⁵⁹

Enhanced recovery techniques are being used to help maintain production in about two-thirds of the oil fields in the Gulf of Mexico. Water, steam or gas are injected into petroleum-bearing formations to maintain pressure, thin out heavy crude oils and force oil to move toward producing wells.

Although the gulf is the nation's most-explored source of offshore oil and natural gas, it clearly has the potential to play a vital role in U.S. energy supply for years to come. But the fact that many of its older fields are being depleted through production makes it essential to continue searching for new oil and gas supplies both there and in other offshore areas. Oil companies are responding to that need. They have announced important new discoveries off the coast of California,

are continuing to explore Alaska's offshore waters, and are returning to the Atlantic Outer Continental Shelf, where several wells discovered the presence of oil and gas, although the commercial producibility of the discoveries has not been proven.

Alaska

Alaska's 365 million onshore acres represent nearly one-sixth of the nation's total land surface. It is more than twice as large as Texas, five times as big as Arizona and 10 times the size of either Illinois, Iowa, Michigan or Wisconsin.⁶⁰

About 74 percent of the nation's total offshore lands are adjacent to Alaska, because of that state's 6,640-mile coastline and the great width of the Continental Margin off its shores.⁶¹

The Department of Energy estimates that Alaska has nearly 8.3 billion barrels of proved crude oil reserves -- 28 percent of the nation's total. DOE also credits Alaska with 33 trillion cubic feet of proved reserves of dry natural gas -- about 16 percent of the U.S. total. Alaska also has an estimated 10 million barrels of natural gas liquids reserves.⁶²

The U.S. Geological Survey estimates that Alaska's undiscovered recoverable resources include:

- Onshore oil -- 6.9 billion barrels.
- Offshore oil -- 12.2 billion barrels.
- Onshore gas -- 36.6 trillion cubic feet.
- Offshore gas -- 64.6 trillion cubic feet.
- Onshore natural gas liquids -- 1.3 billion barrels.
- Offshore natural gas liquids -- 2.1 billion barrels.⁶³

These figures represent mean estimates between the survey's high and low assessments. They indicate that Alaska and its offshore waters have the potential to provide 23 percent of this country's future discoveries of oil, 17 percent of future gas finds and 19 percent of future discoveries of natural gas liquids. The USGS points out that some of these Alaskan resources may become recoverable only if technology can be developed to permit operations beneath arctic pack ice.

The highest USGS estimates suggest that Alaska's onshore and offshore resources could amount to as much as 42 billion barrels of oil and 181 trillion cubic feet of natural gas --- the energy equivalent of 32 billion barrels of oil.

Despite the fact that Alaska is estimated to have the greatest oil and gas potential of any state, relatively few wells have been drilled there except in the Prudhoe Bay, Kenai Peninsula and Cook Inlet areas. Through 1982, slightly more than 1,600 wells had been drilled in Alaska -- an average of one well for approximately each 225,000 acres. By contrast, in Texas, one well has been drilled for each 222 acres, and in Oklahoma, one well for each 124 acres -- and drillers are still finding oil and gas in those states every year.⁶⁴

Because so little exploration and drilling have been done in Alaska and its offshore waters, many petroleum geologists believe the state's oil and gas potential may be much larger than the official government estimates indicate.

Arctic Potential. The National Petroleum Council is even more optimistic than the U.S. Geological Survey about the oil and gas potential of Alaska's arctic region. The USGS and Alaskan officials have estimated the undiscovered hydrocarbon (that is, oil and gas) potential of U.S. arctic areas, onshore and offshore, to be about 27 billion barrels of oil equivalent.⁶⁵ In December 1981 the council -- an advisory committee to the secretary of energy -- put the figure at nearly 44 billion barrels of oil equivalent.⁶⁶

The council said the onshore area north of the Brooks Range of mountains and the offshore areas north of the Aleutian Islands "may encompass a significant portion, perhaps as much as 40 percent, of the total undiscovered recoverable oil and gas resources remaining within the jurisdiction of the United States. On the basis of oil resources alone, as much as 50 percent may occur in the U.S. arctic."

The development of oil and natural gas in the Alaska arctic will be determined by three major factors: (1) the location and size of undiscovered hydrocarbon resources; (2) future energy prices; and (3) the policies developed by the federal government, the state of Alaska and local authorities on the North Slope. Many oil and gas discoveries in the arctic would have been developed already if they had been located within reasonable reach of a transportation system, or closer to markets, or in a more hospitable climate.

Discoveries in remote frontier areas must be very large to justify the investment necessary to develop them. The U.S. Geological Survey has estimated that a field in 100 meters of water in the Beaufort Sea, off Alaska's North Slope, would have to contain at least 100 million to 300 million barrels of crude oil or the equivalent amount of natural gas to be economic. Those figures are more than 100 times larger than the USGS estimate of minimum economic discoveries required in the Gulf of Mexico.⁶⁷

Prudhoe Bay Gas Reserves. The Prudhoe Bay field, on Alaska's North Slope, contains an estimated 26 trillion cubic feet of proved recoverable natural gas reserves -- 13 percent of the nation's total proved gas reserves. For several years, plans have been in the making for a pipeline system to deliver that gas to the lower 48 states.

The plan for the Alaska Natural Gas Transportation System (ANGTS) calls for a 4,800-mile pipeline system that will transport gas from the North Slope of Alaska through Canada to California and Illinois. The system is slated to have an initial capacity of 2 billion cubic feet a day, with future expansion to more than 3 billion cubic feet a day.⁶⁸ That plan was approved by the Congress and the president in 1977. Congress affirmed its support in 1980.

During the years since the North Slope gas was discovered in 1968, the estimated cost of the gas pipeline project has increased to about four times the original figure. By late 1981 the sponsors were estimating that -- after taking inflation and interest rates into account -- the total amount required for the entire pipeline system and a Prudhoe Bay gas conditioning plant was somewhere between \$38 billion and \$48 billion.⁶⁹

Because of escalating costs and problems in arranging financing, the sponsors have extended the target date for completion of the project to 1989, which will be 21 years after the gas was discovered.⁷⁰ They estimate that it will take at least 5 1/2 years to complete the system after financing has been arranged.

Although construction has not begun on the 731-mile Alaskan section of the proposed gas pipeline system, work has been completed on some 1,500 miles in Canada and the United States. In September 1982, federal officials certified the completion and commissioning of the eastern leg of the system, an 823-mile segment that runs from the U.S.-Canadian border near Port of Morgan, Montana, through Ventura, Iowa. The cost of that segment was about \$1.3 billion.

Part of the western leg of the pipeline, extending from Kingsgate, British Columbia, to Stanfield, Oregon, also has been completed and is operating. Pending construction of the complete system, the segments within the United States are being used to deliver Canadian gas to U.S. markets.⁷¹

Because of the difficulties of obtaining financing for the Alaskan segment of the system, several studies have been made to examine alternative methods of transporting arctic gas to markets. Some of the proposals being studied involve piping the North Slope gas to the southern part of Alaska and converting it into either liquefied natural gas or methanol for shipment in

liquid form to either the U.S. West Coast or Japan. However, there has been no general agreement on any of those plans. Economics will play a major role in determining the method that will bring North Slope gas to market.

Actions Affecting Alaska Lands. Some recent developments have opened up certain areas of Alaska for exploration, while other actions have closed off vast areas to energy production.

The state of Alaska has held eight lease offerings in the arctic subregion, including a joint federal/state offering of leases in the Beaufort Sea, off the North Slope. Several commercial discoveries have been made on state leases, including the giant field at Prudhoe Bay. Eight additional state lease offerings are planned for the arctic area.⁷²

Alaskan native groups, operating through the Arctic Slope Regional Corporation, have leased land to several oil companies, which have begun exploring those areas.⁷³

But leases on federal lands in Alaska have been much harder to get -- and, as previously noted, the federal government owns most of the land in that state. Although thousands of applications for leases have been submitted to federal officials since the 1968 discovery of the Prudhoe Bay oil and natural gas resources, no new leases on Alaskan federal lands were awarded until 1982. Current policies, however, appear to offer hope that there will be more rapid movement toward assessing the oil and gas potential of some areas of Alaska.

Late in 1980, Congress adopted a law that placed 104 million acres of Alaskan federal land into various conservation and recreational categories.⁷⁴ Some of those lands are completely closed to oil, natural gas and other mineral development. In some other categories of land, resource development may be severely restricted.

The same law authorized federal officials to allow carefully supervised aerial and surface geological and geophysical studies of the coastal plain of the Arctic National Wildlife Refuge, which lies east of the Prudhoe Bay field. Drilling, which is the only way to find oil or natural gas, is forbidden at present. Five years after the passage of the law -- that is, about the end of 1985 -- the law directs the secretary of the interior to advise Congress whether environmental, geological and geophysical studies indicate that further exploration, drilling and production should be permitted. Thus, it will be several years before accurate information is available on the region's oil and gas potential.

The coastal plain represents less than one-third of the 18 million acres in the wildlife refuge. Based on the limited

scientific information available, the Interior Department has estimated that the coastal plain may contain between 160 million and 17 billion barrels of oil, with a mean estimate of 4.85 billion barrels. For natural gas, the official estimates range from 1.4 trillion cubic feet to nearly 34 trillion cubic feet, with a mean of 11.9 trillion cubic feet -- the equivalent of more than 2 billion barrels of oil.⁷⁵

Another law enacted by Congress in 1980 made it possible to begin competitive oil and gas leasing and drilling in the National Petroleum Reserve-Alaska (NPR-A), which lies west of Prudhoe Bay.⁷⁶

The 23 million acres of land in the NPR-A (about the size of Indiana) were set aside by President Harding in 1923 as a naval petroleum reserve for some future emergency. Congress transferred the reserve to the Interior Department in 1976. Over the years, contractors employed by the Navy and later by the Interior Department drilled a number of exploratory wells in the NPR-A without finding commercially significant amounts of oil or natural gas, although some gas was produced to supply a Navy camp, the town of Barrow and other installations on the North Slope.⁷⁷

The Interior Department has estimated that the NPR-A may contain between 1 billion and 16 billion barrels of oil, with an average probability of at least 6.4 billion barrels. Estimates for natural gas range from 2.5 trillion cubic feet to 27 trillion cubic feet, with an average probability of 11 trillion cubic feet -- the equivalent of about 2 billion barrels of oil.⁷⁸

Current law requires the secretary of the interior to study potential oil and gas resources, transportation possibilities, wilderness characteristics and environmental impacts that could be expected if oil and gas operations were permitted in the Central Arctic area. The study is required to be completed by 1988. A progress report was submitted to Congress in January 1983.⁷⁹

Summary: The Importance of Government Lands

Some analysts have estimated that production from existing conventional U.S. oil reserves will decline by about 60 percent during the next 20 years. They also estimate that, by the turn of the century, about half of the conventional oil produced in this country will have to come from reserves that have not yet been discovered.⁸⁰ Similar forecasts have been made for natural gas.

Because of the long lead times needed to find and bring new oil and gas supplies to market, it is essential that we start

now to find out how much will be available and to create the production, transportation, refining and distribution facilities that will be needed in the future.

As part of that effort, we must make the best use of the potential oil and gas resources of our onshore and offshore government lands. Clearly, many of those areas offer great promise in solving our future energy problems.

In sum, much more oil and natural gas can be found and produced in this country if the federal government opens up more land -- onshore and offshore -- to petroleum leasing. As 1983 began, leases were in effect on about 23 percent of the onshore government lands and on less than 2 percent of the federal offshore acreage. Yet, from those small percentages of the total area under federal control, wells operating in 1982 accounted for:

- nearly 16 percent of this country's production of oil and condensate and
- more than 32 percent of the nation's natural gas production.

(Further discussion of the role of government lands in the nation's energy future is in Chapter VIII.)

4. Government Affects Petroleum Development Through Environmental Laws and Regulations.

During the 1970s, the federal government adopted a series of major environmental laws in response to public concern about environmental pollution. These laws have brought about a substantial improvement in the nation's air and water quality over the past 10 years. The vigorous pursuit of environmental goals, however, has limited the development of this country's resources, including domestic oil and gas. It has also led to increased dependence on imported oil.

Needed: More Flexibility

The nation needs more flexible environmental policies that permit both continued environmental improvement and increased domestic energy development. These objectives are not incompatible.

Reasonable and revised environmental laws and regulations can:

- speed up development of the oil and natural gas on the U.S. Outer Continental Shelf;

- accelerate production of billions of barrels of heavy oil, primarily in California;
- increase recovery of oil in existing fields through use of enhanced recovery techniques; and
- lead to exploration for new oil and gas supplies in some areas of the nation that are presently off limits to petroleum development.

Summarizing the study, Energy: The Next Twenty Years, sponsored by the Ford Foundation, Philip K. Verleger, Jr., who was then a senior research scholar at the Yale School of Organization and Management, concluded that the "authors suggest that the present form of U.S. legislation is far more restrictive than is necessary to achieve the nation's environmental goals."⁸¹ The study itself characterized the government's approach to controlling air pollution as "brute force regulation."⁸²

Environmental Restraints and Roadblocks

Examples of energy-related projects delayed by overly rigid government constraints and excessive environmental opposition can be found from coast to coast. They include numerous instances of oil and gas production delays. Some projects have been held up for years, causing loss or deferral of millions of barrels of oil and billions of cubic feet of natural gas. Some projects have been cancelled entirely.

Off the coast of southern California, environmentalist opposition and regulatory roadblocks held back production of oil from the Hondo field for more than 10 years. Installation of another offshore production platform in California waters was delayed for about 11 years.⁸³ These delays occurred while the United States was growing dependent on foreign sources for nearly half of its oil supply.

Companies seeking permits to produce oil and gas from leases off the coasts of Texas and Louisiana have encountered delays ranging from a few months to a year. Efforts to install enhanced recovery facilities in various areas, and thus increase the flow of oil, also have been held back.

Opposition and regulatory delays have proved fatal to a number of proposed projects for transporting and refining petroleum.

One of the most recent examples was the April 1983 cancellation of plans to build an oil tanker terminal at Port Angeles, Washington, and a 1,500-mile pipeline to move Alaskan crude oil to Minnesota. The Northern Tier Pipeline would have moved about

933,000 barrels of oil a day and would have cost an estimated \$3 billion.⁸⁴

The companies sponsoring the project had obtained about 1,400 permits and had spent more than \$50 million. They gave up after the governor of Washington State rejected an application that had been under consideration for more than four years. The sponsors said a new application would have required at least another year and would have cost between \$8 million and \$10 million, with no assurance that the new plan would win approval. Even if approved, the pipeline could not have been in operation before January 1987.

In 1979, another company abandoned its plan for the PACTEX pipeline, which was intended to carry Alaskan crude oil from California to Texas. The project became uneconomic after a five-year delay in obtaining the necessary federal, state and local permits.⁸⁵

The "Seadock" deepsea port, which was proposed in 1975 to unload oil from giant supertankers off the coast of Freeport, Texas, was never built. After spending about \$15 million on the project, the sponsoring companies withdrew because of excessive licensing restrictions. Two other deepwater ports off the Texas coast have been on the drawing boards for the past few years. They have faced a variety of regulatory hurdles, lawsuits and financing problems.⁸⁶

A number of proposed refinery projects have been delayed for long periods or cancelled because of opposition. More than 11 years have been spent in seeking permits to build a refinery in Portsmouth, Virginia. If the plant had been built in 1971 when it was originally proposed, it would have cost an estimated \$200 million. Now it would cost at least \$1 billion.⁸⁷

Ten years were spent trying to get permission to build a refinery in Eastport, Maine. If that facility had been built in 1973, it would have cost about \$350 million. By the time the sponsoring company abandoned the plan in June 1983, the estimated cost exceeded \$1 billion.⁸⁸

During the past two years, many U.S. refineries have been mothballed or closed down for protracted periods. The shutdowns were caused principally by declining demand for petroleum products, shifts in demand for specific products, changes in the sources and types of crude oil supplies available and the loss of certain advantages that were available to small refiners while oil prices were under federal control.

However, these shutdowns do not mean that the nation needs no new refining facilities. Oil companies have spent more than \$15 billion to upgrade refineries in recent years, and much more

needs to be done.⁸⁹ New equipment is needed to convert heavier grades of crude oil into the light products needed in today's market, to reduce the sulfur content of fuels, to make unleaded gasoline and to improve the environment in other ways.

(Further discussion of energy and the environment is in Chapter VII.)

5. Decontrol of Oil Brightened the U.S. Energy Picture.

Oil and natural gas produced in the United States were the only major energy sources still under direct government price controls at the close of the 1970s.

Oil price ceilings dated from August 1971, when wage and price controls were imposed across most of the U.S. economy. Controls on oil were continued under a series of energy laws adopted during the 1970s. One of those laws provided that oil price controls would become discretionary with the president on June 1, 1979, and would expire altogether on September 30, 1981.

A decade of oil price controls encouraged petroleum consumption while discouraging the search for new domestic supplies. Demand soared and U.S. proved reserves declined sharply. The difference between domestic production and consumption was made up by increasing oil imports. By the late 1970s, Americans were dependent on foreign sources for nearly half of the oil they used. Although controls held down the prices of oil produced in this country, they had no power to restrain the prices charged by other countries for their oil. Because of the heavy demand in the United States and other industrialized nations for imported oil, the world price of oil continued to climb.

In addition, relatively minor supply shortfalls resulting from the Arab oil embargo of 1973-1974 and from the Iranian revolution in the late 1970s turned into major shortages of gasoline and other products for many areas of the United States. The U.S. government tried unsuccessfully to manage these shortages by allocating supplies. Those efforts failed because the formulas and regulations used were too inflexible to cope with fast-changing events.

Two Presidents Take Action

President Carter announced in April 1979 that, on June 1 of that year, he would begin phasing out oil price controls, with all remaining controls to be lifted at the end of September 1981. This was in line with the discretionary powers granted to the president by the Energy Policy and Conservation Act of 1975 (EPCA).

One week after taking office, President Reagan accelerated the oil decontrol date to January 28, 1981, thus removing all remaining price and allocation restrictions from oil and refined petroleum products.⁹⁰

Advocates of continued federal controls strongly criticized those actions by both presidents. They predicted that oil prices would skyrocket, sending gasoline to \$2 a gallon. They said decontrol would bring on a new round of inflation and damage the economy. They charged that oil companies would not reinvest increased earnings in the search for new oil and gas supplies. They insisted that decontrol would do nothing to weaken the power of the oil-exporting nations. They argued that decontrolling oil prices would not significantly restrain demand for petroleum products.

As things turned out, they were wrong on all counts.

What Actually Happened After Oil Decontrol

The removal of federal price and allocation controls on domestic crude oil and petroleum products stimulated the petroleum industry to record levels of activity. Records were set in the number of wells completed, the number of seismic crews at work, the number of active drilling rigs and investments in oil and gas operations.

Oil decontrol also helped to bring a number of other benefits to the nation and to individual consumers:

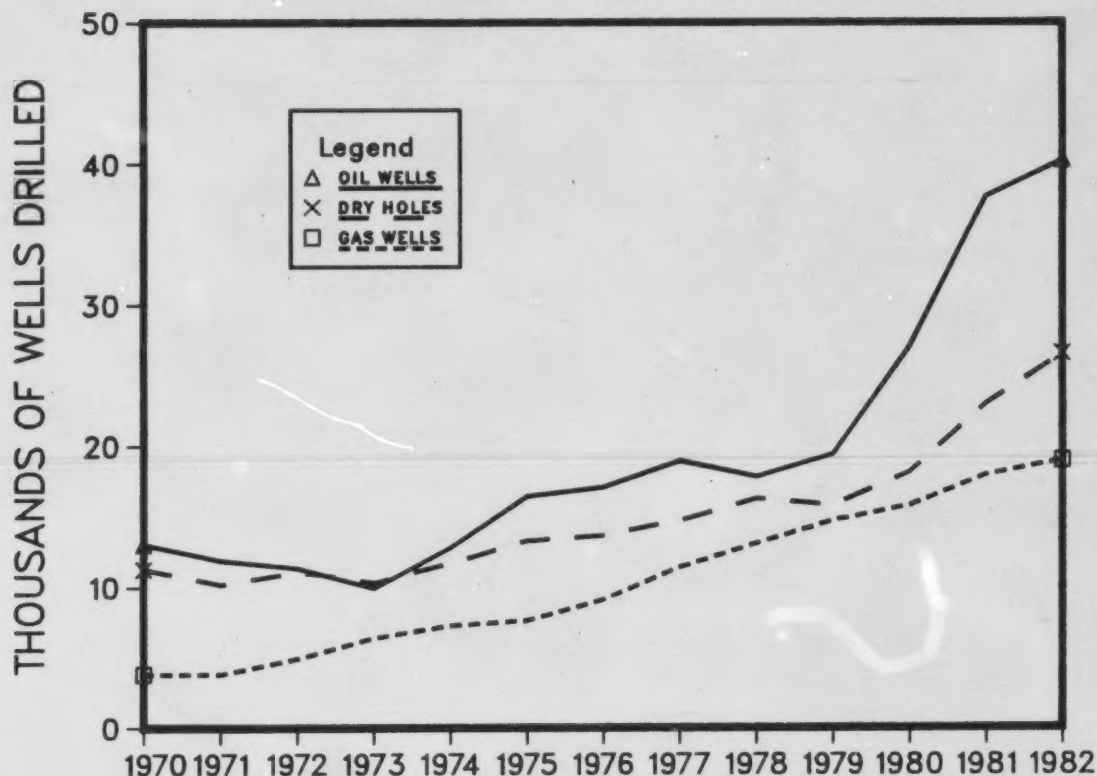
- U.S. oil production stabilized, then began to increase, thus reversing a 10-year decline.
- Americans continued to reduce their energy consumption.
- With oil production up and consumption down, the United States was able to cut its oil imports substantially. This, in turn, helped to reduce world oil prices.

Here are some of the trends in exploration and drilling since oil was decontrolled:

- Wells completed: The number of well completions reported to the American Petroleum Institute during 1982 reached the unprecedented total of 85,800, an increase of 9 percent over 1981.⁹¹ The total included records in all three categories of drilling -- 40,298 oil wells, 18,953 gas wells and 26,549 dry holes. The total number of well completions has more than doubled since 1976. The number of new productive wells reported in 1982 represented an average of one oil or gas well every nine minutes, or 162 wells every day. The United States accounts for about 80 percent of the wells drilled in the non-Communist

world. (See graph, "Total Well Completions Reported to the API.")

TOTAL WELL COMPLETIONS REPORTED TO THE API



SOURCE: SEE APPENDIX

Many of the wells reported during 1982 were actually drilled, or begun, in 1981. Wells are reported as completions only after they have been tested for oil and gas and the necessary permanent equipment has been installed on wells that are ready to produce. Because those steps often take several months, there is a lag between the time drilling stops and the time when a well enters official statistics.

• Footage drilled: The amount of footage drilled in those 85,800 wells totaled a record 396 million feet.⁹² That is the equivalent of drilling 75,000 miles, or drilling 9.5 times through the diameter of the earth at the equator. The amount of footage drilled has nearly tripled since 1972.

● Exploratory wells: Included in the 1982 total were 16,470 exploratory wells.⁹³ That figure broke a record set in 1956. Of the exploratory wells reported in 1982, about 29 percent produced oil or natural gas; the other 71 percent were dry holes.

● New-field wildcat wells: Nearly half of the exploratory wells reported in 1982 were what the industry calls "new-field wildcat wells." These are wells that search for oil and gas in areas that have never previously been productive. Although the risks obviously are greatest in this kind of drilling, wildcats are the only wells that discover new fields. The record year for new-field wildcats was 1956, with a total of 8,742 such projects. The annual number dropped to about 5,000 by 1973, then began to climb again. The industry came close to matching the record by drilling 8,052 wildcats in 1981 and 7,912 in 1982.⁹⁴ In the latter two years, 82 percent of the wildcats turned out to be dry holes. And less than 1 percent of the wildcats reported in 1981 -- one out of every 144 wells -- found reserves estimated at more than 1 million barrels of oil or 6 billion cubic feet of natural gas.⁹⁵

● Development wells: A record 69,330 development wells were reported during 1982, an increase of 9 percent over the previous record set in 1981.⁹⁶ The annual number of development wells has quadrupled since the early 1970s. Even in this type of drilling, which occurs in areas already proved to be productive, the risks are substantial. On average, one out of every five development wells is a dry hole.

● Drilling rigs at work: The U.S. petroleum industry kept an average of 3,105 rotary drilling rigs at work in 1982, according to reports published by the Hughes Tool Company.⁹⁷ Although that was the second highest number in history, it represented a 22 percent decline from the 3,970 figure reported for 1981. Rig activity was at a high level in the early months of 1982, but dropped sharply during the remainder of that year and the first part of 1983, getting down to a monthly average of 1,846 in April 1983. However, by June there were indications a slight recovery had begun.

● Seismic work: Surveys by seismic crews develop geological and geophysical data that help producers decide where to drill for oil and natural gas. After reaching a record annual average of 681 crews at work in 1981, the figure dropped to 588 in 1982. In the first five months of 1983, an average of 452 crews were at work.⁹⁸ Trends in seismic activity are closely watched as indicators of future drilling operations.

What Happened to Gasoline Prices

Contrary to some predictions, the prices of gasoline and other petroleum products did not skyrocket after controls were

removed. Instead, they did what prices normally do in a free market -- they rose when the cost of raw materials increased and when demand was heaviest. They dropped when crude oil costs declined and demand sagged.

Here are the average prices per gallon for all grades of gasoline, including federal, state and local taxes, as reported by the Bureau of Labor Statistics:

January 1981	--	\$1.27	(Just before decontrol)
March 1981	--	\$1.39	(Two months after decontrol)
March 1982	--	\$1.27	(A year later)
March 1983	--	\$1.14	(Two years later) ⁹⁹

The price increase of 12 cents a gallon immediately after decontrol at the end of January 1981 was due in part to the fact that foreign oil-exporting nations had just boosted world crude oil prices to record levels. Prices fluctuated a little during the next 24 months, rising a little in peak driving seasons and dropping at other times, but they trended generally downward. As the government figures show, the average price in March 1983 was 25 cents lower than it had been two years earlier.

The prices quoted from the Bureau of Labor Statistics have not been adjusted to offset the effects of inflation. When that adjustment is made, it becomes clear that, in early 1983, gasoline was selling for less than it had been in mid-1979 when phased decontrol began.

The downward trend in gasoline prices as reported by the federal government was confirmed by various surveys done by the private sector of the economy, including reports by the American Automobile Association and various trade publications. Prices of home heating oil, heavy fuel oil and jet fuel also declined in the two years after decontrol, according to government statistics.

Although the basic price of gasoline was falling during those two years, state and local motor fuel taxes were rising. Surveys by the Oil & Gas Journal indicated that between March 1981 and March 1983 the average pretax price of regular-grade leaded gasoline dropped by more than 20 percent, while motor fuel tax rates increased an average of nearly 16 percent.¹⁰⁰

The federal motor fuel tax, which had remained at 4 cents a gallon since 1959, was increased by 125 percent on April 1, 1983, to 9 cents a gallon. Four cents of the increase is to be used to improve highways and bridges, with one cent earmarked for mass transit projects. Meanwhile, at least 23 states decided to increase their own gasoline tax rates.¹⁰¹

As the spring and summer driving season began, a number of companies that manufacture, distribute and market petroleum products decided to try to recoup some of their recent losses by increasing their gasoline prices a few cents a gallon, to the extent permitted by competitive pressures.

Even after a number of price and tax increases, however, average gasoline prices in May 1983 were considerably lower than in the spring of 1981:

- On May 24, 1983, the Bureau of Labor Statistics reported that gasoline prices in April were 14.1 percent below the March 1981 peak.¹⁰²

- On the same day, the American Automobile Association announced that a survey of 6,000 service stations showed that gasoline prices had increased about 9 cents a gallon in the past eight weeks but were still 13 cents lower than in May 1981.¹⁰³

- Adjusted for inflation, pump prices in May 1983 were about 25 cents, or 18 percent, below their early 1981 highs.¹⁰⁴

Those persons who predicted that oil decontrol would quickly result in gasoline prices of \$2 a gallon had clearly misjudged the impact of supply, demand and competition on energy markets.

After the Boom, a Cooling-Off Period

Some analysts said the record levels of exploration and drilling achieved in the United States were so high that the industry would not be able to sustain them. Events of 1982 proved them right. A combination of economic and political factors abruptly cooled down what some had regarded as an "overheated" industry. Beginning early in 1982 and continuing into mid-1983, sharp declines were reported in the number of seismic crews gathering geological and geophysical data and in the number of rotary rigs actively drilling for oil and natural gas.

In the United States and around the world, recession, energy conservation and the development of new oil supplies created at least a temporary oversupply relative to demand. As demand dropped, sales and prices tumbled and oil company earnings declined. It became harder to attract investment in energy development than it had been a year earlier.

Other factors causing the decline in exploration and drilling since 1981 included high interest rates, high taxes on petroleum companies, the threat of still higher taxes and continued federal control of most natural gas prices at the well-head.

By 1983, even though the rate of inflation slowed from its rapid pace and interest rates began to decline, many drillers

and producers still had trouble in financing drilling projects. Many of them, caught in a cash-flow squeeze, were unable to repay money they had borrowed to finance expanded activities. Consequently, many of them scaled back their operations severely, and some went out of business entirely. Well completions reported to the American Petroleum Institute in the first four months of 1983 were 9 percent below those of a year earlier.¹⁰⁵

Key Factors in the Downturn

As noted above, lagging sales, shrinking profits and high taxes are three of the major reasons for the downward trend in U.S. oil and gas exploration and drilling.

Lagging sales: Consumption of petroleum products in this country has fallen in each of the past four years. Consumption of natural gas has dropped for the past three years.

Comparison of 1982 demand figures with those of recent years illustrates the sharpness of these declines:

- Petroleum products: The Department of Energy estimated total petroleum products supplied in 1982 at less than 15.3 million barrels a day, the lowest average figure for any year since 1971.¹⁰⁶ That represented a 19 percent reduction in demand from the peak figure of 18.8 million barrels a day in 1973. Declines in demand from 1978 through 1982 amounted to nearly 12 percent for motor gasoline, 22 percent for distillate fuel oil and 44 percent for residual (heavy) fuel oil.¹⁰⁷

- Natural gas: U.S. consumption of natural gas in 1982 was approximately 17.9 trillion cubic feet, according to DOE estimates.¹⁰⁸ That was the lowest figure since 1967. It represented a decline of 19 percent from the peak gas consumption of 22.1 trillion cubic feet in 1972.

Declining earnings: Financial reports published by 26 leading U.S. oil companies showed that their total profits after taxes in 1982 were 21 percent below the 1981 level, which had been slightly lower than the 1980 figure. As tabulated by the Oil & Gas Journal, the company reports also showed sharp decreases in their rates of return on stockholders' equity and on total assets.¹⁰⁹

Of the 26 large companies included in the Journal survey, 21 showed declines in net income during 1982. For 13 of those companies, profits dropped in both 1981 and 1982. Some of the largest companies reported declines of more than 40 percent in their 1982 profits. Only three of the leading companies showed gains in both years, and those gains were small in 1982 -- less than 2 percent for one company and less than 1 percent for the other two.

Earnings reports from 20 smaller oil companies told a similar story. As tabulated by the Journal, the 1982 figures showed a drop of nearly 25 percent in total profits after taxes for that group, compared with 1981. Two of the smaller companies reported deficits in 1982.

The first quarter of 1983 found profits still sliding. For 26 leading oil companies, total profits after taxes were down 14.2 percent from the comparable period of 1982.¹¹⁰

Governments Seek New Revenue Sources. As the profitability of oil companies was falling, federal and state governments continued to seek new ways to tax them.

Advocates of higher taxes on the oil industry frequently assert that it is unusually profitable in relation to other industries. Historically, however, the oil industry's rate of return on investment has been about the same, on average, as that for all manufacturing industries. Over the 15-year period 1968-1982, oil companies' weighted average return on equity was 16.2 percent, compared with 14 percent for total manufacturing. The oil industry's rate of return, as reported by Citibank (New York), was below the average for all manufacturing in six of those 15 years, including three of the past seven years.¹¹¹

Citibank's latest report covers 73 petroleum producing and refining companies. Their average profit margin for each dollar of revenue dropped from 4.9 cents in 1981 to 4.2 cents in 1982.

In return on stockholders' equity, petroleum companies ranked 10th in a field of 22 manufacturing industries surveyed by the bank. The oil companies' rate of return on equity fell from 19.7 percent in 1981 to 14.1 percent in 1982. Heading the list in 1982, with an average return on equity of 22 percent, were manufacturers of tobacco products. Other groups reporting higher rates of return than petroleum companies included printing and publishing firms and manufacturers of drugs, soaps and cosmetics, office equipment and computers, photographic equipment, electrical appliances, food products and beverages.

Studies by government agencies, non-oil publications and petroleum analysts agree that the oil industry is one of the most heavily taxed industries in this country.

How Oil Company Taxes Compare. The congressional Joint Committee on Taxation and the General Accounting Office found that a group of leading U.S. oil companies paid 18.6 percent of their before-tax U.S. net income in current federal income taxes in 1981. A sample of leading companies in all industries paid at the rate of 16.7 percent.¹¹²

A similar study by the publication Tax Notes reported that a group of leading U.S. oil companies paid federal income taxes in

1981 at the rate of 21.4 percent in 1981, while leading companies in all industries paid at the rate of 20.5 percent.¹¹³

These comparisons do not include deferred income tax expense, other federal taxes, consumer excise taxes or state and local taxes.

Those two studies confirm that leading U.S. oil companies pay federal income taxes at a higher rate than leading companies in all industries. But federal income tax rates tell only part of the story. Oil producers also are subject to the so-called "windfall profit" tax, which is applied to no other industry.

The windfall profit tax went into effect March 1, 1980. It is misnamed because it is not calculated on the basis of profits earned, but on the difference between the sale price of oil in the field and a base price set by the federal government.

Analyses of the most recent annual reports of 20 leading oil companies reveal that they paid the federal government a total of \$18.6 billion in current federal income taxes and \$29.4 billion in windfall profit taxes during the three-year period 1980-1982. Thus, windfall taxes represented more than half of the oil companies' total federal tax payments.¹¹⁴

When windfall taxes are added to federal income taxes, the total federal tax payments by 20 leading oil companies represented 41.4 percent of pretax income in 1980, 50 percent in 1981 and 43.4 percent in 1982. The average for the three years was 45.5 percent.

By contrast, the most recent annual reports of 100 leading non-oil companies show that they paid a total of \$18.4 billion in federal income taxes in the years 1980 through 1982. Those payments represented 24.9 percent of their pretax income in 1980, 20.2 percent in 1981 and 20.7 percent in 1982. The average rate for the three years was almost 22 percent, or less than half of the 45.5 percent rate paid by 20 leading oil companies in federal income taxes and windfall profit taxes combined.¹¹⁵

For the U.S. petroleum industry as a whole, U.S. Treasury reports show collections of more than \$48 billion in windfall profit taxes in fiscal 1980 through fiscal 1982. The Treasury Department has estimated that it will collect nearly \$13.8 billion in windfall profit taxes in fiscal 1983 and \$12.2 billion in fiscal 1984. Collections are falling below earlier estimates because of declining oil prices.¹¹⁶

The windfall profit tax is playing a major role in reducing the incentive for investment in exploration and drilling. Various estimates suggest that without the tax, U.S. oil produc-

tion by the late 1980s could be 1.5 to 2 million barrels a day greater than it will be with the tax. In all likelihood, any shortfall in domestic oil production will have to be replaced by increased oil imports.¹¹⁷

Federal legislation passed in 1982 increased taxes on the petroleum industry even more. Those actions include the increase of five cents a gallon in the federal motor fuel excise tax, effective April 1, 1983, and several provisions of the Tax Equity and Fiscal Responsibility Act (TEFRA).

A study by the Price Waterhouse accounting firm estimated that six provisions of TEFRA will require 31 large oil companies to pay between \$11.5 billion and \$22.7 billion in additional taxes during the 1983-1987 period. The exact amount will depend on the growth of the industry.¹¹⁸

The increase in the federal motor fuel tax rate is expected to produce about \$5 billion a year in revenue for the government.

Meanwhile, many states are focusing on the petroleum industry in their search for higher revenues. In 1982, some 33 states considered tax legislation that would apply only to the oil industry. And in the first few months of 1983, 23 states increased their motor fuel tax rates. Some states collect a sales tax at the service station pump in addition to the motor fuel tax. Some states also have levied a gross receipts tax on oil companies.

State and local governments collect billions of dollars annually from oil companies, including income taxes, severance taxes based on production of oil and natural gas, and property taxes on oil and gas reserves still in the ground.

6. Decontrol of All Natural Gas Can Provide Many Benefits to Americans.

More than two years of experience have proved that the decontrol of oil was a good thing for the people of America.

Similarly, the removal of government price controls and end-use restrictions from all categories of natural gas can restore a high degree of competition to the nation's energy markets and bring a wide variety of benefits to industries, businesses and individual consumers.

Wellhead prices of natural gas sold across state lines (interstate gas) have been federally controlled since 1954. Gas produced and sold within a single state (intrastate gas) was brought under federal control by the Natural Gas Policy Act of 1978 (NGPA).¹¹⁹

Until 1978, federal regulation kept interstate natural gas prices below those in the intrastate market, where supply and demand were allowed to work. At below-market prices, interstate supplies became scarce. Those shortages became acute for some areas in the 1970s. Pipelines were forced to curtail deliveries. Interstate industrial and electric utility customers were unable to buy as much gas as they wanted. New hookups were banned in many parts of the country. The extremely cold winter of 1976-1977 resulted in supply curtailments that closed commercial establishments and schools and even affected some residential areas.

These shortages were a direct result of a regulatory system that discouraged exploration and production while encouraging the consumption of natural gas. Consequently, consumption far exceeded the discovery of new gas supplies. Between 1956 and 1971, exploratory drilling dropped by 57 percent. Proved reserves of natural gas, which had been around 25 times the annual rate of production in the early 1950s, dropped to about 10 times annual production by the late 1970s, even when the large new reserves on Alaska's North Slope were included.

The 95th Congress tried to solve the nation's gas supply problems by enacting the NGPA. Although that law was often described as a decontrol measure while it was being debated in Congress, it provided only partial decontrol over a period of several years. Besides extending federal controls to the intrastate market for the first time, it also divided natural gas into about two dozen categories, each with its own set of regulations.

Late in 1979, controls were lifted from two categories of "high-cost" gas -- "deep" gas from wells deeper than 15,000 feet and gas produced from geopressured brine, coal seams or Devonian shale. Of these, only "deep" gas is making a significant contribution to current supplies. It is estimated to be providing no more than 5 percent of the nation's total gas supply.

Prices paid for decontrolled "deep" gas soared to around \$9 or \$10 per thousand cubic feet for a while, at a time when the average wellhead price of domestic gas was about \$2. More recently, sagging demand and competitive pressures have reduced "deep" gas contract prices to about half of those amounts.

Under the NGPA, several categories of gas will be decontrolled on January 1, 1985. They will represent about half of the nation's gas production at that time. A little more gas will be freed of controls in mid-1987.

Everything else will remain permanently under federal controls until supplies are exhausted. The General Accounting Office has estimated that, by 1990, controlled gas will repre-

sent between 10 and 25 percent of total production.¹²⁰ Most of the supplies remaining under controls will be gas that was committed to interstate commerce before April 20, 1977. Its price will be adjusted monthly to reflect inflation, but it will be regulated until the reserves run out. Gas from small "stripper" wells also will never be decontrolled under NGPA.

What's Wrong with NGPA

Many studies over the past three decades have concluded that the federal government's attempt to regulate wellhead prices of natural gas in the public interest has been a failure. It is widely agreed that instead of protecting consumers, controls have contributed to shortages and higher prices. They have encouraged the inefficient use of this vital natural resource without adequately encouraging the development of new supplies to replace those being depleted. This has increased Americans' dependence on high-cost imported oil and high-cost imported natural gas.

Price controls and government restrictions under NGPA are further distorting the nation's gas markets and contributing to severe energy problems. Here are a few examples of what is happening under existing laws:

- The system encourages the production of high-cost gas while discouraging the production and use of low-cost gas.

- Average natural gas prices paid by consumers have continued to rise even though much more gas is available than the market can absorb under present conditions. The Interstate Natural Gas Association of America, whose members operate interstate gas pipelines, has estimated the 1983 "balloon of surplus deliverability" for current contracts in the interstate market at 2.5 trillion cubic feet.¹²¹ That is equal to about 14 percent of current U.S. gas consumption.

- Some areas of the country are having difficulty in competing for new supplies of natural gas because the pipelines serving them have little or no access to low-cost, price-controlled gas. Pipelines having a "deep cushion" of price-controlled gas are able to outbid other lines for newly discovered supplies. Under the NGPA, this market distortion will become even more acute in 1985 and the years thereafter.

- Consumers in some parts of the country are paying disproportionately more for the same amount of gas than users in other areas. A recent study by the National Association of Regulatory Utility Commissioners found that the rates paid for natural gas for home heating varied by more than 300 percent in different areas of the nation.¹²² Of course, rates paid by consumers located far from producing areas reflect the transpor-

tation costs involved, but that is only part of the explanation. Market distortions caused by price controls also play an important role.

- In some instances, consumers on one side of a city pay significantly more for gas than consumers on the other side because the suppliers serving the two areas happen to have access to different categories of gas. For example, residential gas rates in the vicinity of Cleveland, Ohio, are reported to vary by as much as 30 percent from one area to another.

- A major producing state finds it more attractive to import gas from other states than to use gas from wells within its own borders.

- Even though there is a surplus of gas at present, the law prevents certain industrial plants from using it.

- Some industries have switched from gas to other fuels because their gas bills increased rapidly. Many of them switched to oil because oil prices were dropping.

- When big industrial users pull out of the gas market, the remaining customers -- including residential users -- must shoulder a larger share of the fixed costs of operating gas transportation and distribution systems.

- U.S. consumers are subsidizing the use of high-cost imported gas. This country's 1982 net imports of natural gas (after deducting gas exports) amounted to 917 billion cubic feet, or 5 percent of domestic consumption.¹²³ In 1982, gas from Canada and Mexico cost about twice the average wellhead price for domestic gas, while the contract price for liquefied natural gas from Algeria was nearly three times the U.S. wellhead price.

- Since the enactment of the NGPA in 1978, the annual growth rate in drilling for natural gas has slowed down, while the growth rate in searching for oil has increased. In the four years 1975-1978, gas-well completions increased at an average annual rate of 16 percent. In the four years 1979-1982, the average annual rate of increase dropped to 10 percent. For oil-well completions, the trend was reversed: 9 percent average annual growth in the first period and a 24 percent yearly increase in the second period.¹²⁴ Comparing 1982 with 1978, the number of oil wells completed increased by 127 percent while the number of gas wells rose by only 45 percent.

Much of what has been said and written recently has sought to blame gas producers entirely for higher gas prices. But the fact is that most of the price increases experienced by residential gas consumers during 1982 were not caused by higher well-

head prices paid to domestic gas producers. Instead, payments for transportation and distribution services and imported gas accounted for nearly 70 percent of the residential price increases.

According to government statistics, the average wellhead value of natural gas produced in the United States in December 1981 was \$2.16 per thousand cubic feet (mcf). By December 1982 it had risen by 40 cents per mcf, to \$2.56. In the same period, the average residential heating price for natural gas rose from \$4.75 to \$6.06 per mcf -- an increase of \$1.31. Thus, while producers' wellhead prices rose by 18.5 percent in 12 months, the cost of other factors increased by 35 percent, or nearly twice as rapidly.¹²⁵

Congress Considers Two Approaches

As the summer of 1983 began, Congress was considering two diametrically opposite approaches to solving the nation's natural gas problems -- phased decontrol of all natural gas versus increased controls.

The Reagan administration urged Congress to phase out wellhead price controls on all categories of natural gas produced in the United States and to eliminate government restrictions on the industrial use of gas. The administration's approach also would protect consumers and encourage the renegotiation of gas contracts that no longer match current supply and market conditions.

On the other hand, some members of Congress introduced bills calling for freezing and rolling back natural gas prices and extending government controls farther into the future.

Many of those advocating the continuation of price controls not only oppose efforts to phase out controls on all natural gas, but also oppose the NGPA on the grounds that they believe it relaxes controls too much. They argue that higher prices will not bring forth additional gas supplies but will place excessive burdens on gas consumers, particularly those in the lower and middle income brackets. Additionally, some have argued that phased decontrol of all gas would require more adjustments in contracts and other gas marketing arrangements than could be accomplished in a limited amount of time.

The administration's approach is strongly supported by the Natural Gas Supply Association, the American Petroleum Institute, the Independent Petroleum Association of America and a wide range of other organizations, including most of the major industrial users of natural gas. In congressional testimony, some of those organizations suggested changing some details of the administration's plan, but they agreed that producers and

consumers alike would benefit from allowing market forces -- supply, demand and competition -- to work.

Groups supporting the administration's approach pointed out that the proposal would apply only to the highly competitive production segment of the gas industry, which includes 12,000 to 15,000 producers. Gas pipelines and gas utility companies would continue to be regulated, as they are now, by existing federal, state or local governmental agencies.

Testifying before a Senate committee in April 1983, Secretary of Energy Donald Paul Hodel summarized the administration's decontrol approach in these terms:

Our objective is to ensure that adequate supplies of natural gas are available to consumers at reasonable prices. There is a consensus that this is not happening under the NGPA, to the disappointment, I am sure, of all of us, the American consumer and those who supported the enactment of that statute.

Decades of federal price controls have resulted in inefficiencies and inequities. The laws and regulations that govern natural gas markets today have produced conditions, reflected in contract terms between producers and pipelines, that are not responsive to current market realities. In fact, under the NGPA, gas pricing is inflexible and is encouraged to go in only one direction: up. As a result, gas prices to consumers continue to rise, despite the availability of plentiful supplies and vigorous competition from alternative fuels, and consumers are paying more than they will in a free market.

The most efficient means for ensuring that consumers have access to adequate supplies of gas at reasonable prices is to remove impediments to the free market.¹²⁶

How the Nation Would Benefit

Advocates of phased decontrol of all natural gas cite these benefits:

- More gas supplies. Producers would be encouraged to search for new, low-cost supplies and to make the necessary investments to keep older fields producing longer. The Natural Gas Supply Association has estimated that an additional 4.3 trillion cubic feet of gas could be obtained over the next 10 years by reworking old wells. A recent oil company study estimated that decontrolling "old" gas and other "forever regulated" gas could result in adding 52 trillion cubic feet of

natural gas to the nation's recoverable proved reserves.¹²⁷ This is gas that would not be produced under continued application of the Natural Gas Policy Act or under further extension of price controls. An increase of 52 trillion cubic feet would increase the nation's total recoverable proved reserves by about 25 percent and would increase by about 50 percent the remaining recoverable reserves in fields that are "forever regulated" under the NGPA.

- More energy conservation. Americans would use gas more efficiently, saving an estimated 1 trillion cubic feet a year -- the equivalent of an additional half-million barrels of oil a day.

- Reduced oil imports. Producing more natural gas and using gas more efficiently would enable the United States to continue reducing its dependence on foreign sources of oil. A recent study estimated that the United States could save more than \$600 billion in foreign oil and gas imports by the year 2000 under the administration's decontrol approach, compared with the effects of continuing under the NGPA. The same study concluded that decontrol also could produce about \$255 billion in revenue for local, state and federal government from income and production taxes and royalty payments. The estimated benefits to the nation from total phased decontrol would be even greater when compared with the effects of proposals to extend federal controls.¹²⁸

- Greater energy security. Reducing oil imports would make this country less vulnerable to international supply interruptions that could damage the economy.

- Lower world oil prices. Cutting U.S. oil imports even further would help hold down world oil prices.

- A stronger domestic economy. Greater supplies of efficiently produced domestic energy, along with better use of natural gas, will increase the nation's overall potential production of goods and services. The Department of Energy and others have estimated substantial real output gains from gas decontrol.

- Market-based pricing. Removing controls would allow gas, like all other energy fuels, to be priced competitively in the marketplace.

- More efficient gas production. With the removal of governmental distortions in the gas market, producers would seek the supplies that could be produced most inexpensively and efficiently, thus delivering gas to consumers at the most economic price.

- Cleaner air. Increased use of clean-burning natural gas would help the nation achieve its environmental goals.

By contrast, extending government controls on natural gas would lay the groundwork for more shortages, increased imports and higher prices in the future.

In summary, the current natural gas price-control system discourages domestic exploration and production. It has forced the premature abandonment of fields containing trillions of cubic feet of gas that could have been produced at market prices. It is distorting the natural gas market, causing some consumers to pay much more than others. And it is threatening consumers with supply shortages within the next few years.

Americans do not have to continue down this self-prescribed road to disaster. By deregulating all domestically produced natural gas in an orderly manner, Congress can allow the market to work in solving our energy problems. By striking a reasonable balance between the various competing interests, Congress can assure America's consumers of plentiful energy supplies at competitive prices for many decades to come.

7. Petroleum Companies Are Working to Find More Crude Oil and Natural Gas.

The nation's petroleum companies are searching vigorously for the crude oil and natural gas supplies this country needs. They have the technology and the skilled people to operate with a high degree of efficiency. And they have demonstrated that energy production can be achieved in harmony with the nation's environmental goals. Their search ranges from the North Slope of Alaska to Florida and from the Rocky Mountains to the depths of the sea. They are:

- searching for new oil and gas fields;
- going after oil that could not have been produced economically under the now-abolished federal oil price controls;
- drilling deeper in areas that are already producing;
- taking a new look at mature producing areas to see if modern technology can find additional supplies;
- using advanced techniques to increase oil and gas recovery and to keep older wells active longer.

Furthermore, because risks and costs are high, the petroleum companies try to develop more efficient ways to find oil and gas, extract them from the ground, process them into useful products and deliver those products to the ultimate consumers.

The annual number of well completions reported to the American Petroleum Institute has tripled since 1973, the year the oil embargo began. The 85,800 wells reported in 1982 were drilled in 35 states and in the nation's offshore waters.

As 1983 began, World Oil magazine estimated that there were 580,142 producing oil wells and 203,663 producing gas wells in the United States.¹²⁹ The wells are located in 33 states and in the waters off the Gulf Coast states, California and Alaska.

Capital Spending Remains High

Capital and exploration expenditures of U.S. petroleum companies reached record peaks in 1981. Faced with declining prices, lagging sales and falling profits, companies were forced to trim their spending plans for 1982 and 1983. Even after that belt-tightening, however, capital and exploration figures remained at relatively high levels.

Between 1968 and 1981, the worldwide capital expenditures of the 25 leading U.S. oil companies increased by 462 percent, from about \$9.6 billion in 1968 to \$53.9 billion in 1981. Most of that investment was for petroleum activities within the United States. The total long-term debt of those companies increased by 300 percent in the same years, from \$12.8 billion in 1968 to \$51.3 billion in 1981.¹³⁰

Over the 14-year period, capital expenditures per year averaged 1.7 times net income and approximately 86 percent of total funds from operations before payment of dividends. Since the oil embargo of 1973-1974, oil companies have committed a higher proportion of their internally generated funds to capital expenditures than have non-oil industrial companies.

Analysis of financial reports published by 22 leading U.S. oil companies indicates that their total worldwide capital and exploration expenditures declined by 5 percent in 1982 from the 1981 level. Their expenditures in 1982 were 2.7 times greater than their profits for the year. Seventy percent of the 1982 capital and exploration expenditures occurred in the United States.¹³¹

Petroleum accounted for 84 percent of total worldwide capital and exploration expenditures by the 22 leading U.S. oil companies during 1982. All energy-related expenditures accounted for 93 percent of the total.

Extrapolating from a survey of leading companies, the Oil & Gas Journal estimated that capital and exploration expenditures by all U.S. oil and gas companies in 1983 will be about 9.5 percent below the 1982 level and 17.5 percent below the 1981 peak.¹³² The Journal's estimate for U.S. capital expendi-

tures by the entire industry are \$82.9 billion in 1981, \$75.6 billion in 1982 and \$68.4 billion in 1983.

The magazine estimated that in 1983, as in the two previous years, about 70 percent of the total will be spent on exploration, drilling, production and acquiring federal offshore oil and gas leases. Because of declines in the cost of drilling and production, the Journal said operators will get more for their money. The magazine said drilling programs in 1983 probably will cost about 70 percent as much as they would have in 1981, when demand for equipment, drilling supplies and personnel reached an all-time high.

Re-Examining Old Producing Areas

It is an old saying -- but a true one -- that a good place to search for petroleum is where it has been found in the past. Producers today are taking a new look at many areas that were productive in the past. They are also exploring areas that did not seem promising with the technology that was available several decades ago, but which may be more accessible today.

Among the areas being re-examined are some of the pioneer producing states where the U.S. petroleum industry was born more than a century ago -- Pennsylvania, New York, Ohio and West Virginia. In the five-year period 1978-1982, the industry completed 43,058 wells in those four states: 19,314 in Ohio, 13,005 in Pennsylvania, 8,336 in West Virginia and 2,403 in New York.¹³³

Much of the increased drilling and exploration activity in the eastern part of the nation is related to the search for oil and natural gas along the Eastern Overthrust Belt, which stretches for about 1,100 miles from Canada down through the Appalachian region into central Alabama. This 60,000-square-mile area is one of the least explored areas in the lower 48 states, but in the past five years considerable interest has been shown in Pennsylvania, West Virginia, New York, Tennessee, Virginia and Alabama, among other states.

The Eastern Overthrust Belt is similar in structure to the Western Overthrust Belt, where major new oil and gas discoveries have been made in recent years. In both areas, pressures deep within the earth caused a thick layer of rock to be thrust atop another layer that otherwise would have been nearer the surface. Thus, some geologists believe that potentially productive sedimentary rock formations may lie hidden beneath other rocks in the Appalachian region. Among recent developments, a number of companies have purchased leases and announced plans to examine some 80,000 acres in the upper Hudson Valley of New York and in Vermont. The first wildcat well

in this program got under way in Washington County, New York, in June 1983.

Drillers have been actively exploring a narrow geological fault zone that crosses Chautauqua and Cattaraugus Counties in southwestern New York State, near the Pennsylvania border. Since mid-1981, an estimated 30 wells have been completed in the area. According to published reports, the productive oil and gas strata appear to lie a little deeper than most earlier Appalachian basin wells have penetrated.¹³⁴

Meanwhile, although the level of activity is lower than in the past year or two, significant exploration and drilling continue in other eastern and southern states, including Illinois, Indiana, Kentucky, Michigan, Ohio, West Virginia, Mississippi and Alabama.

A "Driller's Graveyard" No Longer

Oilmen used to regard the Western Overthrust Belt as a "driller's graveyard," and with good reason. They drilled about 500 dry holes in this geologically complex zone over a period of about 90 years before making a commercially significant discovery. But in the past eight or nine years, the Western Overthrust has become one of the most active exploration areas in the nation. The U.S. Forest Service has called the region "the single most promising area for oil and gas potential in the lower 48 states."

The first commercial discovery in the Western Overthrust Belt was made in northeastern Utah in late 1974. The second was in southwestern Wyoming in 1976. By the end of 1982, drillers had found 26 commercial fields in the Overthrust region of those two states, including seven fields discovered during 1982.¹³⁵ Six of the fields found to date are classified as "giants," meaning that each of them contains at least 100 million barrels of oil or 600 billion cubic feet of natural gas.¹³⁶ As of mid-1983, drillers were still searching for commercial oil or gas discoveries in the Idaho portion of the Overthrust Belt.

In March 1982, Richard Powers of the U.S. Geological Survey estimated that 3.2 billion barrels of oil and 16.5 trillion cubic feet of natural gas had been discovered in the first 19 fields in the area.¹³⁷ The Survey's most recent mean estimates of undiscovered recoverable resources in the Western Overthrust are more than 7 billion barrels of oil and nearly 68 trillion cubic feet of gas. Those figures represent 13 percent of the nation's undiscovered onshore oil and nearly 16 percent of the nation's undiscovered onshore gas.¹³⁸

Preliminary figures covering only part of the Overthrust area indicated that daily production in early 1983 averaged at

least 34,500 barrels of oil and 158 million cubic feet of natural gas.¹³⁹

One oil company has projected that daily production from fields already discovered in the Western Overthrust area could reach 100,000 to 200,000 barrels of crude oil and natural gas liquids and 1 billion cubic feet of natural gas by the late 1980s.

Production of oil and gas from the Western Overthrust Belt has been limited by the lack of sufficient gas processing equipment and the lack of adequate pipeline capacity to transport the newly found supplies.

Companies have invested millions of dollars in solving those problems. For example, a five-company consortium has built the 800-mile "Trailblazer" gas pipeline from southwestern Wyoming to southeastern Nebraska, where it connects with other pipelines serving the midwestern states.¹⁴⁰ Two new gas processing plants were completed in 1982, bringing the total number of plants in the Overthrust area to three. The two new plants have a combined intake capacity of 420 million cubic feet a day. Other facilities are being planned for the area.¹⁴¹

Another restricting factor is federal control of more than half of the lands in the vicinity of the Western Overthrust Belt. The government has withdrawn certain areas from energy exploration and has been slow to grant permits in others.

Some geologists think there could be oil and gas at many other points along the Western Overthrust Belt as it winds from Alaska to Central America. Petroleum discoveries in similar formations in Canada and Mexico add weight to those theories.

Perseverance Produces Results

In many other areas besides the Western Overthrust Belt, experience has taught producers that searching for oil and gas thousands of feet below the earth's surface is far from an exact science.

For example, they drilled 15 dry holes in northern Alaska over a 10-year period at a total cost of \$500 million before finding the giant Prudhoe Bay field in 1968.

And they searched for 78 years before finding commercially producible quantities of natural gas in Oregon in 1979. That discovery made Oregon the 33rd state in the nation currently producing oil or natural gas. The new Mist field in Columbia County is 45 miles northwest of Portland and 50 miles west of Mount St. Helens.¹⁴²

During 1982 the number of completed natural gas wells in the Mist field rose from 8 to 11, but two of those wells were shut in because of water problems. Between January and December, the average daily rate of gas production increased from 8 million to 10 million cubic feet. State officials expect production to increase in 1983 as more of the newly drilled wells go into operation.¹⁴³ By the end of 1982, more than 11 million acres of federal land in Oregon were under lease for petroleum exploration. Considerable leasing also has taken place on state-owned lands.

Across the Columbia River in the state of Washington, drillers are continuing to search for oil and natural gas. Washington produced small amounts of oil in the 1950s, but the field ran dry after about four years. In recent years, some deep wells have been drilled in that state. For example, a well was plugged and abandoned in Kittitas County in August 1982 after reaching a depth of 14,965 feet at a cost estimated in excess of \$10 million. The well found some natural gas, but not commercially significant amounts.¹⁴⁴

Washington State imposed a moratorium on lease auctions of state lands during 1982. As a result, the state government had a backlog of some 400 applications for leases on file by March 1983.¹⁴⁵

Drill Bits Probe Deeper

In many other parts of the nation, producers are drilling deeper in areas that have been productive for years, trying to find oil and gas that may have been missed earlier. Three such areas are Louisiana, the Williston Basin of the Dakotas and Montana, and the Anadarko Basin of Texas and Oklahoma.

- A great deal of deep drilling for gas has taken place in both onshore and offshore Louisiana in recent years. New types of seismic equipment are helping producers to map underground areas more accurately. Some geologists estimate that 6 trillion to 10 trillion cubic feet of natural gas (equal to 1 billion to 2 billion barrels of oil) may ultimately be discovered at depths of 16,000 to 22,000 feet in the "Deep Tuscaloosa Trend" in Louisiana.¹⁴⁶

- The Williston Basin covers about 130,000 square miles in the United States and Canada. It has been an important oil-producing region since the 1950s. Production has declined in recent years, as it usually does in fields that have been active for a long time. However, recent drilling to depths of 15,000 feet or more has resulted in a number of important discoveries.¹⁴⁷ Geologists point out that millions of acres in the basin have not yet been drilled for oil.

• The Anadarko Basin, which was discovered in the 1920s, has recently been the site of a new surge of exploratory and development drilling. Geologists say these wells have explored only about 1 percent of the deep sediments in the basin. Estimates of the natural gas discovered below 15,000 feet range up to 3 trillion cubic feet. Some wells have gone deeper than 20,000 feet. Shallower strata also are being tested.¹⁴⁸

Economic Factors Slow Deep Drilling Trend

By mid-1983, deep drilling had declined sharply from the peak of a couple of years earlier. The reasons most often cited were the current oversupply of oil and natural gas, lower prices for oil and for "deep" gas, high taxes and the reduced sales and earnings of U.S. oil and gas producers. The experience of the past two or three years has demonstrated conclusively that much more oil and gas can be found by drilling deeper -- if the economic situation is favorable.

Industry data compiled in the annual Joint Association Survey on Drilling Costs illustrate three points:

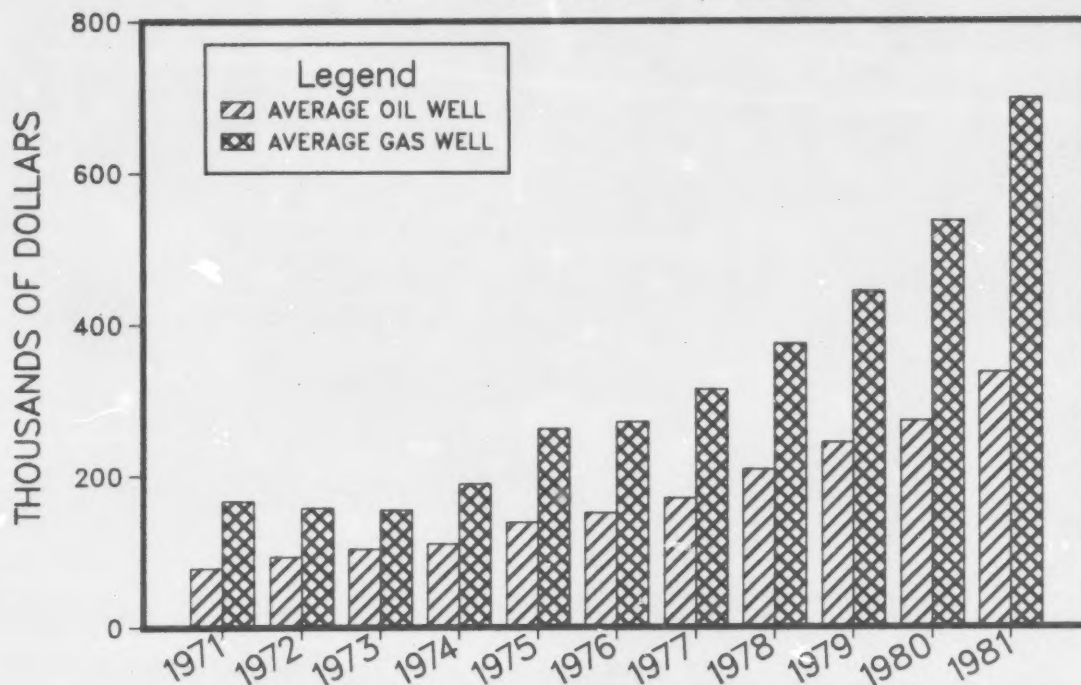
1. Drilling costs have increased sharply in recent years.
2. Offshore wells are much more expensive to drill than onshore wells.
3. Deep wells cost a great deal more per foot than shallow wells.

The cost of drilling and equipping the average U.S. onshore oil well rose from \$65,893 in 1971 to \$311,889 in 1981 -- an increase of 373 percent. The cost of the average onshore gas well went up from \$134,891 in 1971 to \$595,015 in 1981 -- a gain of 341 percent.¹⁴⁹

The average offshore oil well cost \$528,648 in 1971 and \$2,588,744 in 1981 -- up 390 percent. Meanwhile, the average offshore gas well increased in cost from \$765,106 in 1971 to \$4,120,718 in 1981 -- a gain of 439 percent.

When figures for onshore and offshore drilling are combined, the cost of the average oil well rose from \$78,431 in 1971 to \$336,289 in 1981 -- an increase of 329 percent. The cost of the average gas well went from \$166,582 in 1971 to \$698,576 in 1981 -- a 319 percent increase. (See graph, "The Increased Cost of Drilling in the United States.")

THE INCREASED COST OF DRILLING IN THE UNITED STATES



SOURCE: SEE APPENDIX

In 1981 alone, the cost of the average onshore well increased about 26 percent over the previous year, while the cost of the average offshore well rose by 24 percent. The total amount spent in drilling and equipping wells in 1981 was nearly \$36.7 billion -- an increase of more than 60 percent over the figure for 1980. These figures do not include land and lease acquisition costs, bonus and rental payments or geophysical and geological studies.

Average well depths reported in the 1981 Joint Association Survey were: onshore oil, 4,138 feet; onshore gas, 5,588 feet; offshore oil, 8,355 feet; offshore gas, 10,035 feet.

However, at greater-than-average depths, costs escalate rapidly. For example, the average cost of an onshore well between 10,000 and 12,500 feet deep was \$1.4 million in 1981. At depths between 15,000 and 17,500 feet, the cost was more than \$4 million; at depths between 17,500 and 20,000 feet, more

than \$7 million; and at depths greater than 20,000 feet, \$11 million.

Offshore, the average well between 10,000 and 12,500 feet cost \$4 million in 1981. Between 15,000 and 17,500 feet the cost was \$8.6 million; and below 17,500 feet, the average cost per well was \$12 million. The costs of building and equipping large mobile offshore drilling rigs range up to \$180 million each.

Of the wells covered by the 1981 survey, 6,106 onshore wells and 689 offshore wells penetrated deeper than 10,000 feet.

For the past two or three years, a 23,000-foot well in Mississippi has been described as the most expensive drilling project on record, at an estimated cost of \$42 million.¹⁵⁰ But a well being planned for Alaska's Beaufort Sea, near the Prudhoe Bay and Kuparuk fields, is expected to cost more than \$100 million. It will be drilled on one of the most expensive pieces of real estate ever leased -- the Mukluk structure, for which oil companies paid the federal government about \$1.5 billion in cash bonuses in a 1982 lease offering. The U.S. Geological Survey's midrange estimates indicate that the rocks beneath the Beaufort Sea may contain about 8 billion barrels of crude oil and 39 trillion cubic feet of natural gas.¹⁵¹ Those amounts represent 28 percent of the nation's undiscovered offshore oil and nearly 24 percent of the nation's undiscovered offshore natural gas.

What's Happening Offshore

Large-scale oil discoveries off the coast of southern California have dominated the offshore news in the past year. At least five confirmed oil fields have been announced in the Santa Maria Basin, off Santa Barbara. Much more work must be done to define the extent of the discoveries, but some industry observers believe the area may contain several hundred million barrels of oil in several giant fields.

Also off the California coast, companies are continuing to develop the Hondo field in the Santa Barbara channel, the Beta field off Long Beach, the Santa Clara Unit off Ventura County and several other important oil and gas fields. New platforms are being installed, additional wells drilled and pipelines built to transport oil and gas to shore.¹⁵²

In California state waters, an oil company has announced the successful installation of a steel hydrocarbon containment structure as a permanent cap on a natural seep that has been releasing oil and gas into the environment for centuries. The oil and gas are captured and sent to onshore processing plants by pipeline.

The San Francisco firm of Dames and Moore has projected that California's offshore oil production could increase from the 1982 level of about 78,000 barrels a day to as much as 575,000 barrels a day by 1990.¹⁵³ All this activity has revived discussions about building an oil pipeline from California to Texas.

Elsewhere, offshore drilling slowed down during 1982, but not as much as onshore drilling. Offshore projects involve long-range planning and large amounts of money that must be committed well in advance. Therefore, such operations are less subject to short-term, stop-and-start fluctuations in levels of activity. Also, companies that purchase the right to explore offshore tracts must drill on them within the time limits specified in the leases or surrender the leases and forfeit the amounts they have paid to federal or state governments.

The New OCS Leasing Program

The tempo of offshore exploration is expected to quicken under the Interior Department's new five-year program. Practically all of the federally controlled offshore acreage -- about one billion acres -- will be considered for leasing between August 1982 and June 1987. However, government and industry spokesmen expect only a relatively small percentage of the total actually to be leased.

Many areas will be dropped from consideration because of environmental concerns, or because they are believed to have little or no potential, or because they are in water too deep for current technology, or for other reasons. But the important point is that the competing companies, including majors and independent operators, will be able to focus their efforts on the areas they believe to offer the greatest potential for important oil and gas discoveries.

The Interior Department held the first area-wide offshore oil and gas lease offerings under its new streamlined leasing program during the spring of 1983.

In April, oil companies submitted bids totaling a little more than \$86.8 million for leases in the mid-Atlantic area. The apparent high bids amounted to about \$71 million, of which the government accepted \$68.4 million.

A much larger bid-opening, affecting the Gulf of Mexico, took place in May. Companies submitted 1,015 competitive bids totaling more than \$4.5 billion. The apparent high bids amounted to a record \$3.5 billion, of which the government accepted nearly \$3.4 billion for leases on about 3.1 million acres. The federal government expects to receive a total of about \$17 billion in lease bonuses, royalty payments and taxes in connection with these leases.¹⁵⁴

During the past 10 years, the number of active U.S. offshore drilling rigs increased threefold. The offshore industry also has expanded its domestic seismic survey fleet to a record of 69 modern, electronically equipped vessels -- an increase of 30 vessels in only two years.¹⁵⁵

Offshore pipeline construction also is progressing. Offshore magazine recently reported that 44 pipeline projects are being planned or built in the Gulf of Mexico, with 39 of them designed to transport natural gas. Off the U.S. West Coast, four new pipeline projects were listed -- two for gas and two for oil.¹⁵⁶ These new offshore supplies will help to reduce U.S. dependence on foreign energy sources.

Here are three more examples of recent offshore developments:

- The deepest subsea pipelines in the Western Hemisphere are now delivering crude oil and natural gas from the giant "Cognac" platform off the Louisiana coast. The platform is 1,265 feet tall and is the world's heaviest steel platform at 59,000 tons. It stands in water 1,025 feet deep -- the deepest water in which production has been achieved anywhere in the world.¹⁵⁷

Wells on the "Cognac" platform were producing 71,000 barrels a day of crude oil and 100 million cubic feet of natural gas a day by the end of 1982. Companies that have spent some \$800 million developing this property believe the field may ultimately produce at least 100 million barrels of oil and 500 billion cubic feet of natural gas.¹⁵⁸

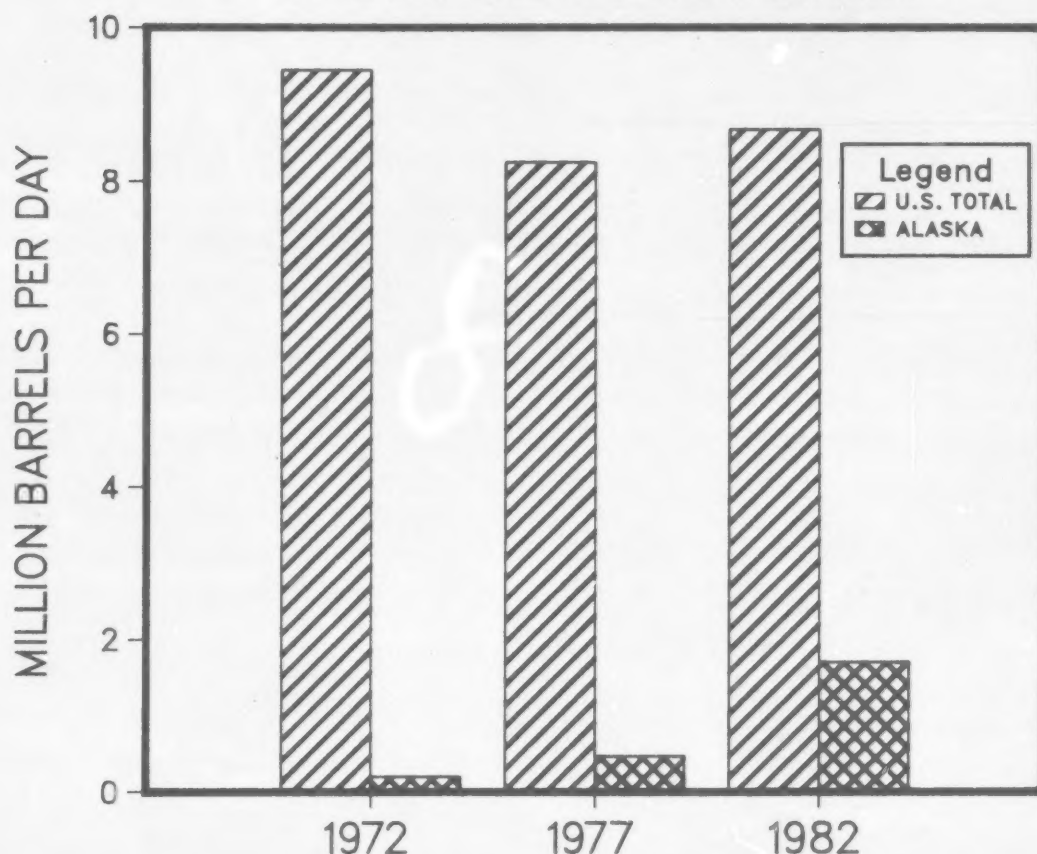
- Another tall tower was installed in the Gulf of Mexico, about 110 miles southwest of New Orleans, during the summer of 1983. Located in more than 1,000 feet of water, it is the world's first commercial guyed tower offshore platform. Twenty guy lines anchor the tower to the seabed. The design permits the tower to move with the winds and waves and then return to its normal position. The tower itself is 1,078 feet tall. With decks and drilling rigs added, the total height is 1,300 feet. Some 58 production wells are planned for the area surrounding the tower, with production expected to start in 1984.¹⁵⁹

- In the eastern Gulf of Mexico, drilling interest currently centers around Mobile Bay, where a major natural gas discovery was made in 1979. Drilling rigs are continuing to explore the nearby waters and onshore areas to establish the perimeter of the discovery and the volume of gas available. Some recent wells have probed deeper than 20,000 feet.¹⁶⁰

What's Happening in Alaska

Alaska provided more than 618 million barrels of oil in 1982 -- nearly 20 percent of the nation's production.¹⁶¹ (See graph, "Alaska's Growing Importance in U.S. Oil Production.")

ALASKA'S GROWING IMPORTANCE IN U.S. OIL PRODUCTION



SOURCE: SEE APPENDIX

Oil companies have invested billions of dollars in Alaska. The 800-mile Alaska oil pipeline alone accounted for nearly \$9 billion. Through 1982, another \$9 billion had been invested in developing the Prudhoe Bay field. Total investments in Prudhoe

Bay development through 1986 could exceed \$16 billion, according to the companies operating there.¹⁶²

The Prudhoe Bay oil field is the largest ever discovered in North America. It produces 1.5 million barrels of crude oil a day -- the maximum production level allowed by the state of Alaska. By the end of 1982, a total of 2.6 billion barrels of oil had moved through the 800-mile pipeline to Valdez and thence by tanker to the lower 48 states. So far, about 545 wells have been drilled in the Prudhoe Bay field, of an eventual 788 wells planned.¹⁶³

Even giant fields decline after producing for a while, so the companies operating the Prudhoe Bay field have already begun taking steps to maintain production. In August 1981, they began drilling wells on 80-acre spacing rather than 160-acre spacing in certain portions of the field. In addition, they built a two-million-barrel-per-day seawater treatment plant to be barged to the North Slope as part of a waterflood project. The facility is expected to be in operation in 1984. The water will be injected into oil-bearing formations underground to force the oil to move toward producing wells. By the late 1980s, plans call for injecting about 3 million barrels of water a day.

Thirty miles west of the Prudhoe Bay field, oil production from the Kuparuk field began in December 1981. By the spring of 1983 this new field was producing about 100,000 barrels a day. The oil moves by a special pipeline to a point where it can be fed into the main pipeline running from Prudhoe Bay to the southern coast of Alaska. The field is estimated to contain more than one billion barrels of oil.

Oil production from the Kuparuk field is expected to increase dramatically in coming years with further development, including a waterflood program. The company operating the field estimates that with sufficient effort, the field could be producing as much as 250,000 barrels a day by the late 1980s. That would make it the second largest producing field in the United States, exceeded only by Prudhoe Bay. About \$700 million have been invested in developing portions of the Kuparuk field. The cost of full field development, including the waterflood program, is estimated at \$7 billion.

Meanwhile, oil companies are continuing to explore and evaluate other areas on the North Slope of Alaska and in the waters of the adjacent Beaufort Sea. Oil and gas have been found in at least 10 other locations. Production from some of them could begin by the late 1980s, by which time the flow of oil from Prudhoe Bay may be declining.¹⁶⁴

Producing More Oil from Known Fields

Although exploratory drilling will be extremely important in maintaining petroleum production, much of the oil this country will need in coming years does not have to be discovered. It has already been found. Existing fields contain an estimated 300 billion barrels of oil which have not been producible, either because the technology was lacking or because the expense involved was too great. Continued improvements in economic incentives and technology, along with reasonable environmental regulations, will make it possible to recover more of that oil.

As one example, a Department of Energy (DOE) study published in 1981 suggested that a large potential for enhanced recovery exists in Texas oil fields that were abandoned because they were no longer economic to operate.

That report listed 676 onshore Texas oil fields, each of which produced at least 250,000 barrels of oil before the volume fell so low that the fields had to be closed down. Cumulative production from the fields studied was 760 million barrels. Many of the fields have never been subjected to secondary recovery techniques such as waterflooding, in which water is injected underground to force oil to move toward producing wells.

"Assuming customary ratios of production to crude remaining in the formation," the DOE study said, "there would be more than one billion barrels of crude oil still in place and subject to secondary or tertiary production." The Department of Energy hopes today's higher oil prices will make it economic for companies to go back to some of those old fields and try to achieve additional production.⁶⁵

Conventional production methods, on average, have recovered from the ground only about one-third of all the oil ever discovered in this country. About 40 years ago the industry developed waterflooding, which today is instrumental in producing about half of this country's oil. However, that method also leaves large amounts of oil in the ground.

In recent years the industry has developed several new methods of increasing oil recovery. They involve the use of heat, chemicals and various gases and fluids to thin out oil in rock formations, loosen it from the tiny pores in the rocks or otherwise cause it to flow toward producing wells. These methods are expensive to use and some of them require months or years to produce significant results. When domestic oil production was under federal price controls, such techniques often were too costly to justify their use.

Current enhanced recovery processes fall generally into three groups: thermal, miscible and chemical.

- Thermal recovery heats thick, heavy oils and makes them flow more easily through the reservoir. Heat can be provided by steam injection or by injecting air and burning part of the oil underground. Thermal recovery techniques (steam and combustion) produce about 80 percent of the oil from enhanced recovery projects listed in a recent Oil & Gas Journal survey.¹⁶⁶

Steam projects in Kern County, California, are partly responsible for California's status as the fourth largest crude oil producer in the United States. The Kern River field steam drive project is by far the most prolific thermal operation reported in the survey. It produced 83,000 barrels a day in 1982, an increase of 59 percent since 1980.

- Miscible flooding consists of injecting a fluid -- usually carbon dioxide -- that dissolves in the oil it contacts and makes the oil flow more readily. Success of this method depends on several factors, such as reservoir pressure, the volume of gas used and its impurities.

A recent DOE report says carbon dioxide miscible displacement (CO₂ flooding) is one of the most promising enhanced recovery technologies. Some companies estimate that this method may increase oil production from certain fields by 10 to 15 percent. It has been estimated that more than 50 trillion cubic feet of carbon dioxide will be required to recover oil in the Permian Basin of Texas and New Mexico alone.¹⁶⁷ Pipelines are being built to transport carbon dioxide from Colorado to oil fields in west Texas.

- Chemical flooding is the most complex and least developed of the enhanced recovery processes. However, it may have the greatest potential for maximum recovery. Chemicals are injected to make the oil mix more readily with water. Then, water is injected to move the oil to producing wells, after which the expensive chemicals can be recovered and used again. A heavy polymer may be added to the water to slow it down and spread it out so that more oil is contacted.

Recently a successful test was completed in the Loudon field in southern Illinois, using a chemical system specifically designed to be effective at a high salinity of 104,000 parts per million. The test recovered 60 percent of the oil in place.¹⁶⁸

The Oil & Gas Journal estimated in April 1982 that enhanced recovery methods add about 375,000 barrels a day to the nation's crude oil supply. That represents about 4 percent of

total daily production. Oil companies and the Department of Energy are jointly sponsoring a number of enhanced recovery experiments, at a cost of several hundred million dollars.

A market study by the firm of Frost & Sullivan, Inc., has estimated that the oil industry will spend a total of \$38 billion on enhanced recovery operations in this country during the decade 1979-1988. The total includes spending for oil field equipment, services and injection fluids. The study estimated that these activities can increase the nation's oil production by as much as two million barrels a day.¹⁶⁹

With adequate incentives and continued technological advances, most estimates indicate that future production of oil in the United States could be increased by around 30 billion barrels with the use of the newer techniques. That would represent a doubling of current proved reserves.

Small Is Beautiful, Too

Every driller hopes to discover another Prudhoe Bay field, but even small wells play an important role in the nation's petroleum supply. Nearly three-fourths of the producing oil wells in the United States are classified as "stripper wells," meaning that they are capable of producing no more than 10 barrels a day. As 1982 began there were nearly 410,000 such wells in operation. Their average daily production in 1981 was a little less than three barrels a day, but together they provided one out of every seven barrels of oil produced in this country.¹⁷⁰

Producers invest a lot of time, money and effort in keeping even small wells operating as long as it is physically and economically possible to do so. The alternative, of course, is to close down the wells and abandon hope of recovering whatever oil they might have produced. The National Stripper Well Association estimates that fields served by stripper wells may contain more than 4.4 billion barrels of oil reserves.

Each year, several thousand wells that formerly produced more than 10 barrels a day become so depleted that they are downgraded to stripper status. And each year, production volumes decline so much in relation to the costs involved that several thousand wells have to be closed down permanently. In 1981, for example, 7,215 oil wells were plugged and abandoned.

Preliminary figures indicate that the nation's stripper wells produced about 439 million barrels of oil during 1982. That was an increase of 12.5 million barrels, or 3 percent, over the figure for 1981. The association noted that the so-called windfall profit tax had an adverse effect on stripper well production in 1980, 1981 and 1982 but added that an exemp-

tion that became effective on January 1, 1983, should help keep many small wells active longer.¹⁷¹

Companies' Role in Research

U.S. petroleum companies concentrate most of their research and development efforts on developing improved technology for finding, producing, transporting and refining petroleum.

For example, oil companies have developed highly sophisticated equipment for recording, processing and analyzing seismic data that are vital in helping producers decide where to drill.

They also have developed production platforms capable of operating in water depths far beyond the reach of conventional offshore equipment, used satellite photography to help find oil, built computerized models to simulate the production response of underground oil reservoirs, invented new catalysts to increase gasoline yield at refineries by as much as 40 percent and developed safer transportation methods for oil and petroleum products. And, along with other leading industries, oil companies are working to develop new forms of energy.

Summary: Actions the Government Can Take

The ability of the United States to develop its energy resources efficiently will be greatly influenced by the federal government's economic and tax policies and by the availability of potentially productive government lands, both onshore and offshore.

The Bankers Trust Company has estimated that capital expenditures of more than \$700 billion will be needed in this country between 1982 and 1990 to minimize declines in oil and gas supplies and thereby hold down U.S. dependence on foreign energy sources.¹⁷²

High taxes on domestic oil and gas producers tend to reduce investment in developing new supplies and thus increase this country's need for imported energy.

Here are some of the actions the federal government can take to strengthen the nation's energy future:

- recognize energy production as one of the high-priority uses that can be made of government lands;
- review and, as necessary, revise federal environmental and land-use rules and policies to ensure that they help maximize domestic energy production and, at the same time, protect the environment, wildlife and other values;

- permit orderly access to government lands, both onshore and offshore, for exploration, development and production of energy resources by responsible, competitive private companies;
- reduce the time required to obtain permits;
- restore the principle of allowing two or more compatible uses of government lands to coexist, where that is feasible;
- coordinate the overlapping responsibilities and contradictory regulations of the many agencies involved in the use of government lands;
- remove price controls and end-use restrictions on natural gas; and
- adopt tax policies that encourage exploration and production of this country's abundant energy resources.

* * * * *

The Comptroller General of the United States sent a report to Congress on December 7, 1979, about trends in U.S. petroleum and natural gas production. That report, prepared by the General Accounting Office, reached these conclusions, which are still valid:

Any policy designed to encourage petroleum and natural gas production must have two equally important purposes:

- To provide adequate incentives to drill for new reserves and improve recovery in existing fields.
- To provide incentives to focus new drilling activities in the areas where it is most likely to find new large fields (e.g., the frontier areas of Alaska and the OCS).
- To aim for one with little attention given to the other will significantly impair the likelihood of success for any government initiatives to stimulate domestic oil and gas production and thereby restrain oil imports.¹⁷³

* * * * *

Positive actions by the government can encourage maximum production of domestic oil and natural gas to help the United States achieve greater energy security by 1990.

III. COAL

Coal is the most abundant fossil fuel in the United States. It accounts for about 80 percent of known recoverable U.S. energy reserves. In fact, the United States has some 60 percent of the entire free world's coal reserves.

For years, coal was the country's major source of power. First mined in the later half of the eighteenth century, it quickly replaced wood as the primary fuel. By the early twentieth century, coal provided almost 90 percent of the nation's energy. Today, however, it supplies only about 22 percent of our energy.

Over recent years, U.S. demand for and production of coal has increased slowly but steadily as the cost of competing fuels has increased and concern about nuclear energy has grown. In 1979, coal companies produced 776 million tons. Production reached 830 million tons in 1980, dipped slightly in 1981, but then increased in 1982 -- to 833 million tons.

Coal consumption in the U.S. rose nearly 10 percent in 1979 over the previous year to some 680 million tons. In 1981 consumption reached 733 million tons. This increase in demand was attributable to higher prices for imported oil, which encouraged utility and industrial users to switch to cheaper, more readily available coal. With the 1981-82 economic recession, consumption fell somewhat in 1982 -- down to 707 million tons. The recession curtailed demand for all energy and prompted mines and industrial users to stockpile coal until demand picked up. As the economy recovers, coal consumption will probably outpace production until stockpiles are reduced. Exports of U.S. coal also increased over recent years, thus accounting for most of the differences between coal production and coal consumption.

Some people feel that by burning coal, the nation is stepping backwards. They argue that coal cannot be mined or burned without harming the environment and that coal is a fuel of limited use. In fact, the nation can expand the use of coal, while continuing to improve the quality of the environment. The technology already exists, and is in use, to mine and burn coal in environmentally acceptable ways. Furthermore, coal can

be changed to clean-burning liquid and gaseous fuels that can directly replace petroleum. The costly technology of producing synthetic fuels, however, prevents full-scale switching to coal-based fuel.

Moreover, abundant and reasonably priced supplies of coal can help boost the nation's economy. First, if the nation chooses to accelerate the development of its coal reserves, American industries will have greater access to more reliable and less expensive energy supplied by coal. Second, because coal costs less than fuel oil, electricity generated by coal can hold down the cost of electricity to homeowners and other consumers. Finally, money paid for coal stays in the United States and thus improves the nation's balance of payments.

Forecasts show coal consumption in the United States increasing from the 1979 level of 680 million tons a year to between 890 million tons and 1.1 billion tons in 1990. If the nation chooses to use its huge coal reserves and to resolve the political and other problems constraining coal, coal use in this country could double over this decade and reach 1.3 billion tons by 1990. This would be the equivalent of about 14 million barrels of oil a day, about three times the oil the United States now imports.

This chapter examines three aspects of coal's potential role in the energy market: resources and reserves, producing more coal and consuming more coal.

Resources and Reserves

Several different terms categorize the potential and known amounts of coal to be found in the United States. The categories and their estimated amounts are:

- Resources -- 4 trillion tons.
- Proved reserves -- 1.7 trillion tons.
- Minalable reserves -- 473 billion tons.
- Recoverable reserves -- 237 billion tons.¹

The recoverable reserves of coal (defined as coal that can be extracted under current technology and current economic conditions) contain the energy equivalent of 911 billion barrels of oil. That is 31 times America's current proved crude oil reserves.

More than half of the minable coal reserves lie west of the Mississippi River, scattered beneath 20.6 million acres in Wyoming, Montana, Colorado, North Dakota, New Mexico and Utah.

The Powder River basin of northeastern Wyoming and southeastern Montana contains about 60 percent of western minable coal reserves. That region has unusually thick deposits near the surface. The seams are up to 120 feet thick and contain an average of about 200,000 tons of coal per acre.

The rest of the nation's minable coal reserves are located in the Appalachian and midwestern states. Kentucky, West Virginia, Pennsylvania and Illinois have 80 percent of these minable reserves. About two-thirds of the reserves in Appalachia and the Midwest are located in relatively thin seams at depths of 200 feet or more. The average thickness of a coal seam in this area is five feet -- a third of the average thickness of a coal seam in the West.

Western coal differs somewhat from Appalachian and midwestern coal. Most Appalachian and midwestern coal is bituminous with a high heat and relatively high sulfur content. Much of the western coal is subbituminous with a lower heat content and smaller percentage of sulfur. Western coal contains on average only 1 percent sulfur by weight and thus emits fewer sulfur compounds -- sulfur dioxide and sulfuric acid -- than eastern coal, which contains 2 to 4 percent sulfur.

Producing More Coal

Most coal in the East is mined by underground methods, while western coal is usually more accessible by surface mining. Most U.S. coal production -- 60 percent -- comes from surface mines in both the East and West.

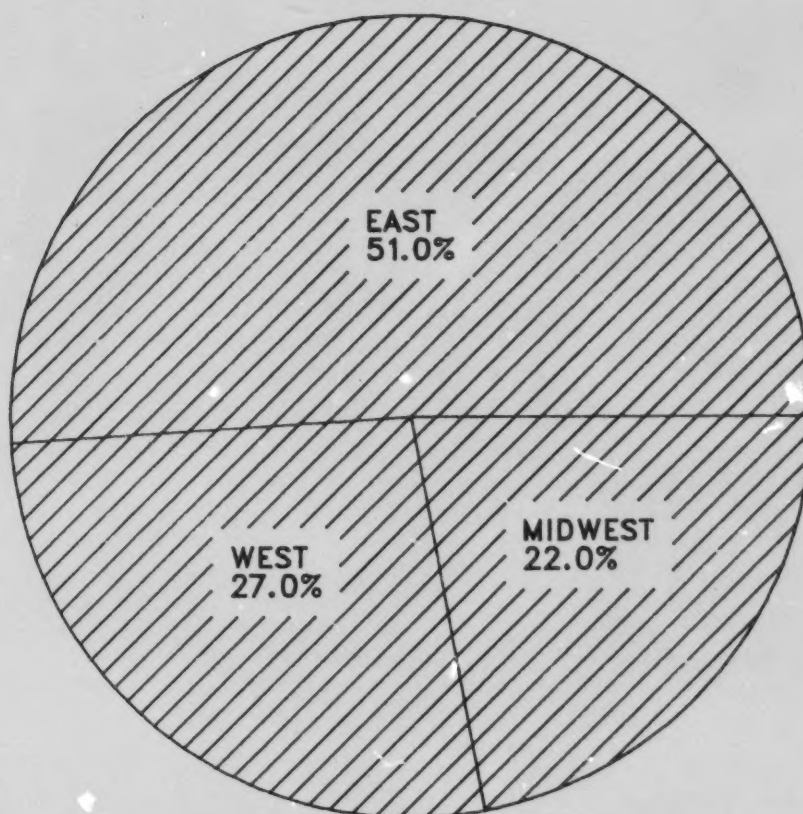
The majority of U.S. coal production in 1982 -- 73 percent -- was in the Appalachian and midwestern coal fields. (See graph, "Regional Sources of Coal Production in 1982.") During that year, Kentucky was the major coal mining state, with more than 18 percent of total U.S. output. West Virginia and Wyoming were next, together providing 28 percent of coal production.

The Powder River basin is the major coal producing area in the West. The Department of Energy (DOE) expects production in this region to reach about 205 million tons a year by 1985 and nearly 400 million tons in 1990. Thus, the basin could account for at least 30 percent of national coal production by the end of the 1980s.

Coal on Government Lands

While most coal reserves in the East are privately owned, western coal is largely held by the federal government. In the West, about 60 percent of coal is government owned and an additional 20 percent is privately owned but dependent on govern-

REGIONAL SOURCES OF COAL PRODUCTION IN 1982



SOURCE: SEE APPENDIX

ment lands for access. Thus, the federal government owns or controls about 80 percent of western coal reserves.

The western coal reserves controlled by the federal government are concentrated in six states: Colorado, Montana, New Mexico, North Dakota, Utah and Wyoming. These six states pro-

duced just over 104 million tons of federal coal in fiscal year 1982, approximately 12 percent of total U.S. coal production for the year.²

In 1971, the Department of the Interior (DOI) imposed a moratorium on coal leasing. At the same time, the department undertook a new program to increase pre-lease analysis and ordered that an environmental impact statement on the leasing program be prepared. The new program was adopted in early 1976 and was immediately challenged in court. The following year, the court directed DOI to prepare a revised environmental impact statement.

In 1979, DOI adopted an entirely new program, which is still in effect and called the Federal Coal Management Program (FCMP). The program assumes that future demand for coal can be accurately predicted and that the amount of coal the country will need can be translated into the amount of coal tonnage that should be offered in coal lease sales.

At the time, Executive branch agencies, such as the Department of Energy and the Justice Department, criticized the program's methodology, including the process of setting desired production levels and tonnage targets for leases. DOI was also criticized for overstating the amount of coal to be produced from existing leases, for not accounting for the adverse impact of new land use planning regulations and for not considering the high economic costs to the nation of under-leasing.

In 1982, DOI promulgated final coal leasing regulations that addressed many of these criticisms. The changes modified the concept of "leasing targets" and simplified the leasing process. Instead of "targets," DOI will set leasing levels that meet industry's need for reserves and accommodate a wide range of cost, quality and output requirements. DOI will allow industry to become involved earlier in the land use planning process and will assure that leases issued before the 1976 Federal Coal Leasing Amendments Act remain consistent with the terms under which those leases were issued.

The Interior Department conducted its first lease sales since 1971 in 1981. In April 1982, the government conducted the largest federal coal leasing sale in history, leasing the rights to mine an estimated 1.6 billion tons of coal in the Powder River basin of northeastern Wyoming.

Coal leasing has opponents. They say that the government allows lessees to hold on to property for speculative purposes, that existing leases are sufficient to meet the country's coal needs, and that further leasing is environmentally unsound.

Coal Mining and the Environment

The coal industry has recognized and is addressing environmental concerns that have hampered coal mining and consumption.

Past coal-mining practices -- which took place under laws and regulations in force at the time -- sometimes damaged the environment. Today, however, most coal companies follow mining and reclamation procedures that restore the land to an acceptable ecological condition. Through land reclamation, pollution control and water conservation, government and industry can continue to protect the environment while greatly expanding coal production.

Local landowners, outdoor recreationists and residents are concerned about the possible impact of surface mining. However, strict federal and state laws require reclamation of mining areas immediately after production. Companies that do not reclaim mined land are subject to government fines.

In areas where coal seams are unusually thick, productive mining can take place on a relatively small amount of land. In the Powder River basin, for example, miners can extract approximately 200,000 tons of coal on average while disturbing only about one acre of surface area.

Typical of land reclamation practices is the McKinley mine near Gallup, New Mexico, operated by the Pittsburg and Midway Coal Mining Company, a subsidiary of Gulf Oil Corporation. At the mine, reclamation begins as soon as coal is removed. Topsoil is saved and, after bulldozers regrade the land to the approximate original contour, the topsoil is returned and reseeded, fertilized and mulched. New Mexico State University scientists, like other agricultural researchers in the region, have developed seed mixtures for the McKinley mine that increase the productivity of the forage for livestock in the area.

In Gillette, Wyoming, Sun Company is mining coal at its Cordero Coal Mine and, nearby, is running Big Horn Ranch -- a working cattle ranch and reclamation research center. New techniques of planting are being developed here so that mined land can be returned to a more useful state than before mining.

Water Demands. In the semi-arid West, water could be a major constraint on commercial coal development. Coal companies and residents are concerned about the impact of coal mining on aquifers (water-bearing rock formations beneath the ground) and about the water needs of proposed synthetic coal fuel projects, coal-fired power plants and coal pipelines.

Studies by the U.S. Geological Survey and other federal agencies indicate, however, that the water supply in the West

is sufficient for mining, as well as for agricultural and population demands.

A January 1980 report of the General Accounting Office's Community and Economic Development Division concluded that "adequate water is available for energy development through at least the year 2000." The report called "unfounded or outdated" predictions that energy development in the West would virtually exhaust the water supply there.³

The activities in the Powder River basin, which draws water from the Yellowstone River, are a case in point. Roughly 11 percent of the river's flow is used for agricultural irrigation. By contrast, all mining in the region uses about 0.04 percent of the river's water supply. The Water Resources Council estimates that, if coal production in the region increased to the unusually high level of 232 million tons a year by 1985, mining would use 1 percent of the river's average annual flow.⁴

Constraints on water supplies arise from conflicting water rights and competing water needs, more than from actual shortages. Current energy activities illustrate that the coal industry and other users can successfully allocate and share water resources.

Air Pollution. Coal mining without proper controls raises clouds of dust that do not resettle quickly in arid windswept areas of the West. Tiny particles of coal and soil, if left uncontrolled, can affect visibility and cause difficult breathing for people near surface mines.

Mining companies control dust pollution by spraying roads and exposed areas with a chemical binder that holds the surface together. They also reclaim mined areas immediately after the coal is removed in order to prevent erosion and to reduce the possibility of pollution from dirt and other particulate matter. (The problems of controlling air pollution that may result from burning coal are discussed later in this chapter.)

Consuming More Coal

Coal use can be increased substantially by resolving a number of regulatory, economic and environmental questions. The principal market for more coal in the 1980s and beyond is the electric utility industry.

Utility and Industrial Use of Coal

Electric utilities are, and will continue to be through the 1980s, the major consumers of coal in the United States. (See graph, "Coal Consumption by End-Use Sector.") They now account

for 82 percent of the demand for coal. In 1982, coal-fired plants consumed about 594 million tons of coal and generated approximately 53 percent of the nation's electricity. Coal consumption by utilities is projected to increase to around 800 million tons a year by 1990 according to the North American Electric Reliability Council.⁵ Of the approximately 2,900 electric power plants in the United States, 500 burn coal. And utilities are planning for a total of 275 new units during this decade.

Coal use can also be increased by operating existing coal-fired plants at higher capacity. The electric utility industry has already moved in this direction, mainly as a result of sharp increases in world oil prices in 1979-1980. Utilities with extra coal-fired capacity have sold power to systems with oil-fired capacity. This practice accounts for part of the increased use of coal over the past few years.

In addition, power plants and large industrial boilers now using oil or natural gas can be converted to coal. Also, burning a coal-oil or coal-water mixture can increase coal use and reduce oil use in plants that cannot readily be converted to coal alone. The technology and economics of this process have recently improved and demonstrations and tests in Florida, Kentucky and Mississippi are moving to the commercial stage.

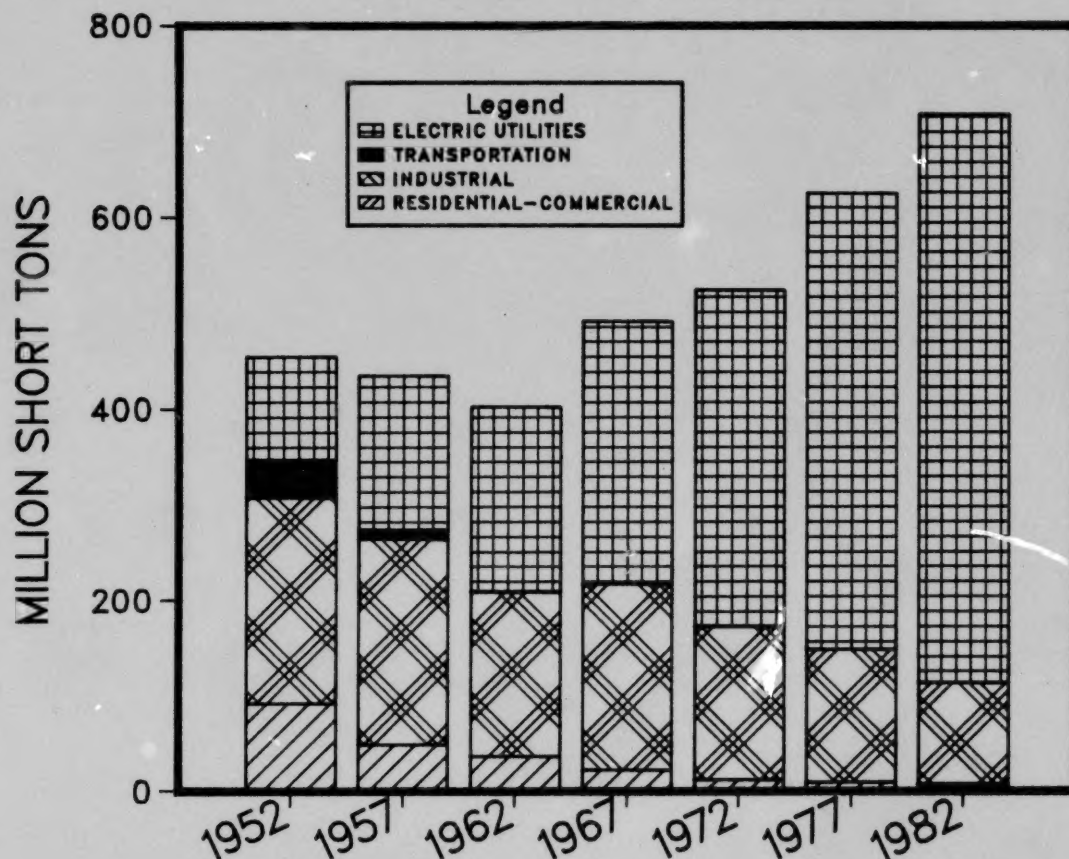
Industrial use of coal is expected to increase about 4 percent from its 1982 level of around 72 million tons to 75 million tons in 1983.⁶

Increased coal use can reduce oil imports. Utilities and the industrial sector in 1982 consumed 4.5 million barrels per day (mbd) of oil and 4.8 mbde (million barrels per day equivalent) of natural gas. If 100 million tons of additional coal are burned, this country could reduce imports by 390 million barrels of oil per year. Such a reduction would halt the payment of approximately \$11.3 billion (oil at \$29/barrel) for imported oil.⁷

Legislation. Congressional interest in converting electric power plants from oil and gas to coal resulted in the passage of several pieces of legislation in recent years.

After the 1973-74 oil embargo, Congress passed the Energy Supply and Environmental Coordination Act (ESECA). It prohibited certain power plants that can burn coal from using petroleum and required that new boilers fired by fossil fuels be designed to burn coal. The goal of this law was to replace 0.3 mbde of oil and gas.

COAL CONSUMPTION BY END-USE SECTOR



SOURCE: SEE APPENDIX

In 1978 the Powerplant and Industrial Fuel Use Act (FUA) revised and extended the provisions of ESECA and set a short-term goal of replacing 0.4 mbde of oil and gas by 1985. FUA intended to reduce the use of natural gas and oil in new electric power plants or industrial boilers and, by 1990, the use of natural gas in existing power plants. It also required that all new power plants be capable of burning coal or alternative fuels. When the FUA was passed, there was concern that natural gas was a dwindling resource with relatively unpromising future production prospects. This perception has since been shown to be unnecessarily pessimistic.

In 1981, Congress repealed the requirement that electric utilities halt gas-fired generation by 1990. The repeal of the so-called off-gas provision means that utilities are not required to convert to coal power after 1990.

Although the intent of these laws was good, restrictions on fuel use have become cumbersome and uneconomical. Reliance on market influences has proven to be a more efficient way to deal with changing fuel needs. In practice, conversion of existing facilities has generally been slow except when economic conditions have favored conversion.

Regulatory Conflicts. Environmental regulations, specifically portions of the Clean Air Act, Clean Water Act, and the Surface Mining Control and Reclamation Act, have created obstacles to coal conversion. The Department of Energy has noted with respect to existing power plants:

Environmental considerations will generally not prevent conversion of units, but compliance with environmental laws and regulations can delay the conversion process or raise conversion costs so high by requiring the upgrading or installation of pollution control equipment that conversion becomes economically unattractive.⁸

Many of the legislative and regulatory restrictions have been based on false assumptions or unsubstantiated conclusions, such as the insistence that all coal must be cleaned of sulfur, regardless of how little sulfur is in it.

Both government and industry recognize that, before the United States can make much greater use of coal, the regulatory process will have to be streamlined and made more flexible.

Financial Obstacles. Uncertain and escalating financial costs have discouraged some utilities from converting existing units from fuel oil to cheaper coal. Conversion may require a multi-million dollar investment for new coal-handling equipment, pollution control devices and changes in boilers. Pollution control devices alone, specifically scrubbers, will cost each utility \$1 billion a year over the next decade.⁹ Also, many utilities -- with their regulated rates of return -- have cash flow or capital availability limitations that create difficulties in acquiring loans for improvements. The cost of conversion could impose debts that many utilities could not carry.

In an overview of the industry, the chief executive officer of one of the country's largest coal-producing companies concluded:

Pure economics are likely to be the catalyst in future conversions to electric-generating power plants ... high capital costs and interest rates and major uncertainties about the future of clean air regulations will prevent a wholesale approach to utility plant conversions any time in the near future.¹⁰

Moving Coal

As the country uses more coal, it will need to develop more efficient, economical and environmentally acceptable systems for moving coal. Some of these systems, such as railroads and waterways, already exist but need to be further improved or expanded. Others, particularly coal slurry pipelines, need to be constructed.

Upgrading the Railroads. Trains are the major coal carriers in the United States, handling more than 60 percent of the coal produced here. Most of this coal has no alternative economic means of transport. In 1981, trains carried over 500 million tons of coal which comprised 35 percent of all rail freight tonnage.¹¹

About half of the coal carried by rail moves on unit trains, which are composed of at least 100 hopper cars dedicated to carrying coal. In order to handle the volume of coal safely and efficiently, railroads will need to upgrade parts of the system, for instance, expand coal piers and add branch lines. Recent legislation has significantly reduced rail carrier rate regulation and allowed the railroads to charge higher rates in order to upgrade and expand their equipment.

The cost of transportation is vitally important to the health of the industry. For coal companies in the West served by a single railroad, transportation costs can represent up to two-thirds of the final price of the coal. In other parts of the country, where distances to the marketplace are shorter and railroads compete with other modes, transportation accounts for about one-third of the final price.¹² The president of the National Coal Association has concluded: "The most critical issue facing the coal industry domestically and internationally is the transportation cost because the delivered price of coal is the bottom line."¹³

Water and Truck Transportation. A comprehensive analysis by MIT of the role of coal -- called the World Coal Study -- pointed out the need for alternatives to railroads for inland transport. In the United States, barges and other vessels currently carry 11 percent of all coal supply; trucks transport 12 percent; a small amount is moved by pipeline; and 11 percent is consumed at the mine for generating electricity.¹⁴

Both waterways and trucking are limited alternatives for transporting coal. On the one hand, waterways provide the most efficient and least expensive way to move coal, but there are no waterways serving many coal mining areas, especially in the West. On the other hand, the high cost of trucking coal discourages the use of motor vehicles to haul coal over long distances.

Coal Slurry Pipelines. A practical and potentially economical means of long distance transport is the coal slurry pipeline. To move in a slurry pipeline, the coal is first crushed to small pieces and then mixed with water or another liquid. The coal-liquid mixture (or slurry) is then sent through pipelines.

Only one coal slurry pipeline is currently in commercial operation in the United States. The Black Mesa line transports nearly 5 million tons of coal annually 273 miles from north-eastern Arizona to southern Nevada. However, a number of other pipelines have been proposed for construction in various sections of the country. One of the longest, which would pipe coal 1,400 miles from Wyoming to Arkansas and Louisiana, could be operating by 1985. Another nine pipelines are in various planning stages.¹⁵

Government and private studies indicate that, in certain situations, coal slurry pipelines are the most economical and the most environmentally acceptable way to transport coal. However, the issues of rights-of-way, eminent domain and acquisition of water rights are delaying construction.

Companies need rights-of-way in order to construct coal slurry pipelines because pipelines invariably cross lands controlled by other forms of transportation, principally the railroads. Only 12 states have enacted eminent domain statutes providing access to such lands. Without eminent domain, disputes on pipeline right-of-way acquisition can be resolved only through time-consuming and costly litigation. The company building the Wyoming to Arkansas pipeline, for instance, has fought 65 court battles in six states in order to obtain necessary rights-of-way.¹⁶

The question of water rights is also a concern, especially in the West. Local authorities are reluctant to grant water rights to pipeline companies when they must also meet the demands of farmers, ranchers and small industries. However, slurry pipelines, which need about a ton of water or other fluid for every ton of coal, use considerably less water than generating plants or coal gasification plants located at mines.

The General Accounting Office January 1980 report on water availability indicated:

Since coal slurry lines can use water that is too contaminated or too expensive for other purposes, the technology should not have much impact on other water consumers. 17

In sum, transportation does pose obstacles to increased coal use, but these obstacles can be overcome so that more coal can be moved from the mine to the marketplace.

Exports

U.S. coal exports have grown substantially during the past several years. Exports rose from 8.5 percent of total coal produced in 1979 to 12.8 percent in 1982. Projected long-term worldwide economic growth suggests that a trend has been set by increased foreign demand for U.S. coal. Much of this growth can be attributed to conversion of electric utilities and industrial boilers from oil to coal.

For the short-term, coal exports in 1983 are expected to drop 13 percent to 92 million tons from the 1982 level of 106 million tons. Most of the drop is the result of reduced demand for metallurgical coal, which is used to produce steel. Exports of steam coal, a variety of bituminous coal that is a feedstock for utilities, are expected to decline in 1983 from 27 to 25 million tons. Exports should rise over the long term, according to the National Coal Association, to 138 million tons in 1990.

Coal Use and the Environment

Greater coal use depends on environmentally sound methods of mining and burning coal based on practical laws and regulations.

Burning coal in the old way -- without modern pollution controls -- would pollute air and water. The pollution control devices now in place on most coal-burning equipment have sharply reduced the emission of pollutants into the atmosphere. However, total control of emissions from coal-fired boilers has not yet been achieved. Pollutants from coal burning include sulfur dioxide, nitrogen oxides, carbon dioxide and particulates (dust, soot, fly ash and other tiny particles of solid and liquid matter).

Current Technology. The technology to limit emissions of these pollutants exists and is being used by many coal-burning facilities. This technology includes the following techniques and equipment:

- Coal washing. Coal can be cleaned before burning to remove some of the impurities.

- Electrostatic precipitators. This equipment reduces particulate emissions. The newest precipitators are considered to be 90 to 99 percent efficient in removing the larger particles.

- Flue gas desulfurization. These devices, commonly called scrubbers, control the emission of sulfur oxides. As of the end of 1981, 94 scrubbers were in commercial operation; a total of 220 scrubbers are in place, under construction or planned.¹⁸ According to the Environmental Protection Agency, scrubbers installed in large electricity-generating power plants remove up to 95 percent of sulfur emissions.

Other Environmental Concerns. Public attention has recently been given to several broader environmental concerns that could effect the increasing use of coal. These involve acid rain, the greenhouse effect and solid waste disposal.

- a. Acid Rain. Some scientists conclude that rainfall in parts of the world, including areas of the United States near the Canadian border, has become more acidic in recent years. Some scientists attribute the acidity to emissions from coal-fired utilities, but other scientists question these findings and disagree on the causes and effects of acid rain. While various specialists do not agree on the causes and extent of acid rain, many believe that further scientific research is needed.

- b. Greenhouse Effect. When coal (or any other fossil fuel) is burned, carbon dioxide emissions occur. In itself, carbon dioxide is harmless -- nature itself is a major source. However, some scientists believe that large concentrations of carbon dioxide in the atmosphere can, in time, change the climate by creating higher temperatures worldwide. This is the so-called greenhouse effect.

Other scientists are more sanguine about the presence of carbon dioxide in the atmosphere. Some scientists detect a cooling phenomenon as counteracting the greenhouse effect. They speculate that such activities as forest clearing, livestock overgrazing and increased land aridity have, over the centuries, resulted in a higher degree of reflected sunlight from the earth's surface. The more sunlight the earth reflects, the cooler it gets.¹⁹

Members of the World Coal Study concluded that present knowledge of carbon dioxide effects on climate "does not justify delaying the expansion of coal use." The study added, "It may happen that some effects of CO₂[carbon dioxide] will become detectable on a regional and global scale before the end of the century."²⁰

c. Solid Waste. A third problem is the disposal of the solid wastes that result from controls on sulfur emissions. Most scrubbers, installed in the past by large coal-burning facilities, produce a solid waste called sludge. The sludge from the scrubbers has to be disposed of in an environmentally acceptable way, but this is proving difficult because of a lack of sufficient disposal sites.

Scrubbers are now available, however, that do not create sludge but instead produce usable and marketable sulfur solutions and pure sulfur.

The Environmental Problems Are Solvable. Government and industry leaders alike agree that coal can make a much greater contribution to the nation's future energy needs in an environmentally safe way.

The President's Commission on Coal, after a two-year study, concluded that "the problems associated with coal use can be overcome, and that this nation must begin to rely more heavily on its vast coal deposits to reduce much of our intolerable dependence on imported oil."²¹

The World Coal Study concluded: "Coal can be mined, moved, and used in most areas in ways that conform to high standards of health, safety and environmental protection."²²

Meanwhile, many new processes and techniques are being demonstrated in pilot plants or are undergoing testing in research facilities. These processes and techniques can be grouped into three categories: Coal cleaning processes, emissions control devices, and synthetic fuel from coal.

a. Coal cleaning processes. These remove many of the impurities from coal before it is burned. The coal-cleaning process of washing coal before it is shipped to utilities and industrial plants is already in use in some regions. In its simplest terms, the washing separates the coal from its impurities (ash-producing minerals and sulfur). Still, according to the Electric Power Research Institute (EPRI), existing technologies must be improved upon and newer technologies developed. These would include effective methods to dispose of the wastes resulting from coal cleaning.

As with other emerging technologies, coal-cleaning offers a double benefit. Removing impurities and drying surface moisture results in a coal that emits fewer pollutants and has a higher heat content.

EPRI estimates that, by 1985, more than one-third of the coal used by the utility industry will be physically cleaned. "Cleaning technologies," EPRI says, "will permit using the

large coal reserves of the interior and Appalachian regions of the United States that otherwise could not be used under sulfur oxide emission requirements."²³

b. Emissions-control devices. These are more sophisticated devices which remove pollutants during coal combustion. For example, electrostatic precipitators control emissions of very fine particles given off during coal burning.

An advanced coal burning process, called "fluidized bed" combustion, removes the sulfur from coal as it is being burned. The fluidized bed system uses a stream of air to suspend a bed of limestone particles. Pulverized coal is then injected into the bed. According to engineers at the Massachusetts Institute of Technology Energy Laboratory, these fluidized bed combustors offer high combustion efficiency and still meet EPA standards for sulfur and nitrogen oxide.²⁴

A device that has been used to control emissions from fluidized bed and other types of coal burners is also being adapted to reduce or remove emissions of fine coal particles. This device, called a baghouse, consists of thousands of bags (one foot in diameter and 30 feet long) generally made of glass fiber. The baghouse traps the particles, preventing them from being emitted into the atmosphere. Use of baghouses on a small scale has produced efficiency figures of 99.8 percent removal of total particulate mass and better than 99 percent for the small particles, according to EPRI. Baghouses are not in general use, however, because of the high cost of maintenance and further experiments with alternative types of fibers.

c. Synthetic fuels from coal. These are produced by converting coal to a liquid or gaseous form. The conversion process removes the potential pollutants and produces a clean fuel that can be used in existing combustion boilers and internal combustion engines. A number of experimental processes are being tested to burn coal directly in a more environmentally sound way. One approach has been to modify the coal chemically to remove some of its impurities.

Chemically treating coal modifies its structure and characteristics but offers the promise of providing a clean solid form of fuel. One process is called Solvent Refined Coal (SRC). In this process, coal originally high in sulfur and fly ash is mixed with a solvent and treated with hydrogen at high temperature and pressure. Several oil companies are involved in SRC research and development, and pilot plants in Alabama and Washington have been operating since 1973.²⁵

The basic technology for changing coal to liquid or gaseous form -- that is, producing synthetic fuel -- has been available

for many years. South Africa already has an extensive capability to convert coal into clean liquid fuels. One plant has been operating for several years; a second, much larger plant went into operation early in 1980 and a third went into production in mid-1982. With all three plants in operation, oil from coal now accounts for about 50 percent of South Africa's total petroleum consumption.

In this country a number of oil companies have experimented with making synthetic fuels from coal. (These fuels are discussed in detail in Chapter V.)

Conclusion

In the coming years, this country will need to produce more energy, and much of this power must come from coal. Despite reductions in oil imports and the energy savings made through conservation, more energy will be needed for industrial growth and to maintain the standard of living. While distant future growth may be fueled by new energy sources, the energy needs in the coming decades will have to be met by expanding existing sources, especially coal power.

The World Coal Study has summarized the importance of coal in powering this nation through the 1980s and 1990s:

Building a bridge to the energy source and supply systems of the next century -- whatever they turn out to be -- is of crucial importance. We believe that coal can be such a bridge and that it will also continue to serve a vital role in the longer-term future.²⁶

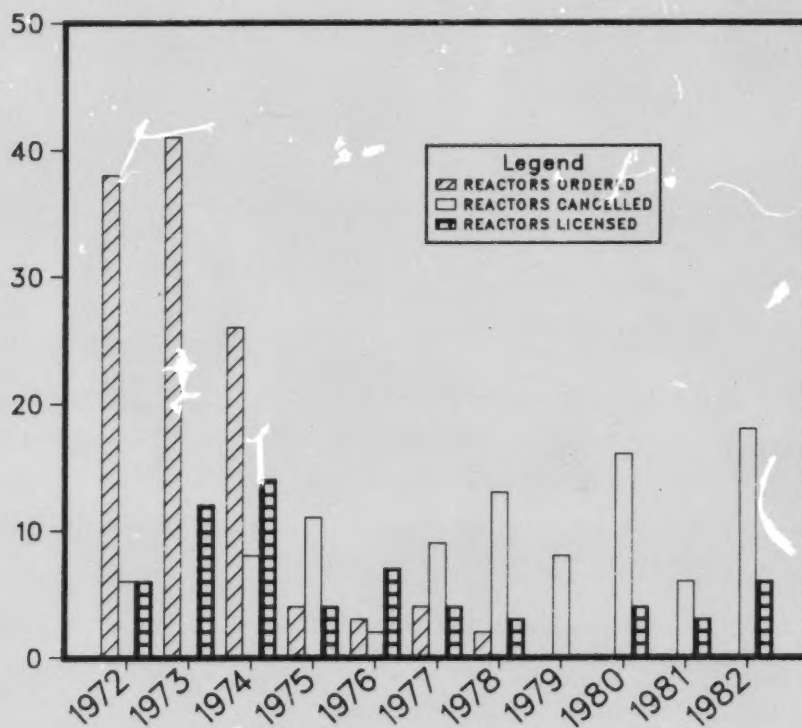
The United States has nearly 32 percent of the estimated worldwide coal resources and more than one-half of the free world's coal resources. We thus have a unique opportunity to help reduce dependence on oil from insecure sources and to reduce pressure on world oil markets, while ensuring continued economic growth.

IV. NUCLEAR ENERGY

Two sharply different opinions about the long range future of nuclear energy in the United States have emerged in recent years.

One view holds that nuclear power will have, at most, a severely limited role in the total U.S. energy picture. Supporters of this view point out that no new orders for reactors have been placed since 1978, and numerous projects have been cancelled; electricity demand has declined; power plant construction costs have soared; the Supreme Court has ruled in effect that states may veto future projects until the federal government has permanent waste disposal facilities; and the public has become increasingly apprehensive about nuclear safety since the Three Mile Island accident. (See graph, "Nuclear Reactors Ordered, Cancelled and Licensed.")

NUCLEAR REACTORS ORDERED, CANCELLED AND LICENSED



SOURCE: SEE APPENDIX

A different view, cautiously positive, holds that despite some setbacks, nuclear power is poised for a "new era." Supporters point to an improving economy that is certain to be accompanied by a rise in demand for electrical power; the decline of both inflation and interest rates, which will improve the climate for construction programs; the adoption by Congress of a waste disposal program; a Supreme Court decision barring psychological factors as a reason for blocking nuclear power; and signs that the now cumbersome regulatory process may be streamlined.

Whatever the long term may hold, nuclear power has been making slow but steady progress in the decade of the 80s. Nuclear plants provided 12.6 percent of the electricity produced in the United States in 1982, according to the Department of Energy (DOE). (See graph, "Net Generation of Electricity by Fuel Type.") That represents an increase from 11.9 percent in 1981. The output of operating nuclear plants in 1982 was about 1.5 million barrels a day of oil equivalent (mbde). (See graph, "Nuclear Electricity Generation.")

As of April 1983, there were 85 reactors with licenses to operate; 57 reactors with construction permits, and 5 on order.¹ The Atomic Industrial Forum, Inc. (AIF), an industry group, forecasts that 39 operating licenses will be issued during the next few years: 7 during 1983, 14 in 1984, 8 in 1985 and 10 in 1986. "With this bulge in new capacity," AIF says, "1983 promises to be the year that nuclear power moves into second place, behind coal, as a producer of electricity."² In so doing, nuclear power would surpass natural gas.

Many analysts expect that, despite the nuclear industry's many problems in the United States, growth will continue during the rest of the current decade. Projections of nuclear production in 1990 range from 1.4 mbde to 3.8 mbde.

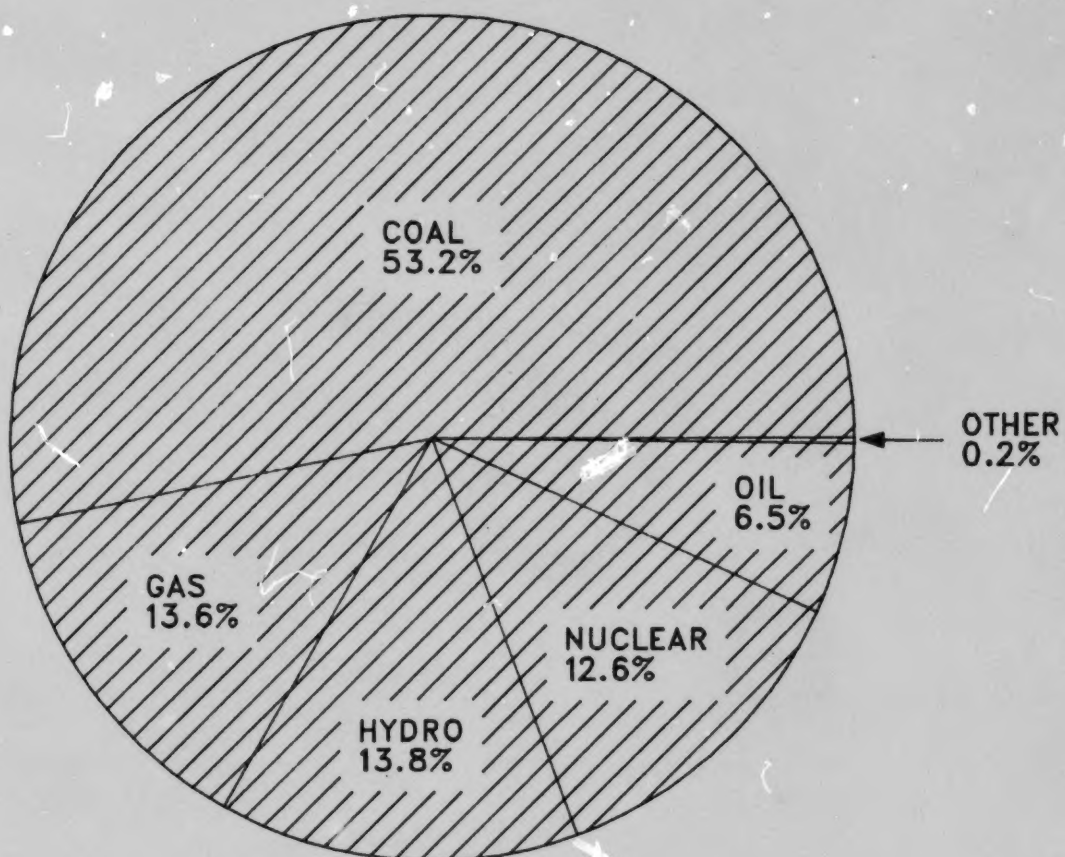
While the range in estimates is considerable, reflecting the great number of uncertainties in the nuclear power picture, nuclear energy will still have a key role in further reducing imports of oil during the decade.

Background

Nuclear energy has a significant role to play in the nation's overall energy picture because the United States has been shifting toward reliance upon electrical power. Since less than 13 percent of the nation's electric power is now being generated with nuclear fuel, there is considerable room for growth.

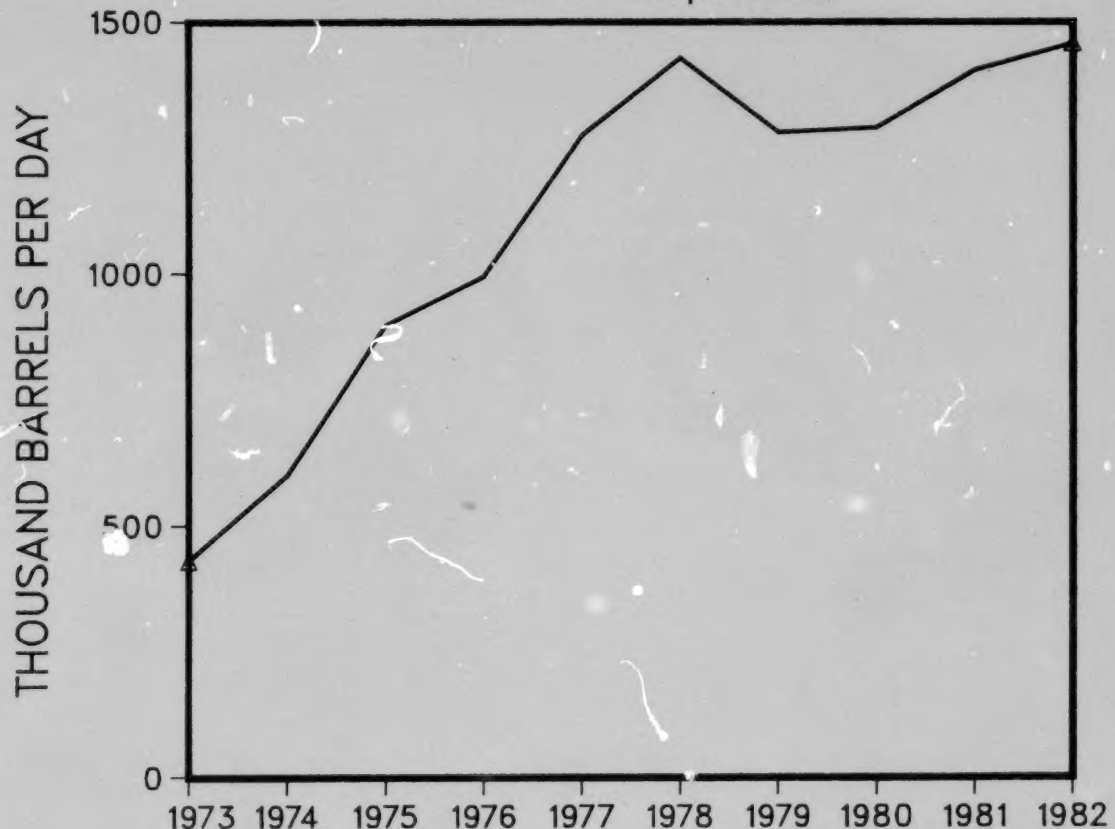
In the early 1970s, forecasts for nuclear energy were quite optimistic, predicting levels of 7 mbde or higher for the late

NET GENERATION OF ELECTRICITY BY FUEL TYPE IN 1982



SOURCE: SEE APPENDIX

NUCLEAR ELECTRICITY GENERATION IN THE UNITED STATES in crude oil equivalent



SOURCE: SEE APPENDIX

1980s. However, doubts about nuclear's future soon began to surface, and the forecasts began dropping. After the accident at Three Mile Island, the future appeared even less certain. Opponents of nuclear energy began calling for the shutdown of all existing nuclear power plants. Fast-rising construction costs and high interest rates further clouded nuclear energy's future.

Current forecasts suggest that nuclear power will continue its growth, but at a slower pace than envisioned during the 1970s. AIF has projected that, based on current utility commit-

ments, installed capacity will increase about two times, compared with 1982, by 1990.³ This implies production of about 2.6 mbde. Figures from a 1982 estimate of the North American Electric Reliability Council show that nuclear power generation will increase to the equivalent of about 3.8 mbde by 1990.⁴

The United States has adequate reserves of uranium to support this anticipated growth. According to the Department of Energy, the nation has 889,000 tons of known uranium reserves and considerable amounts of probable reserves.⁵ The Nuclear Energy Policy Study Group (a group sponsored by the Ford Foundation) says that "uranium resources will probably be adequate well into the next century."⁶

Mills to extract uranium and enrichment facilities to concentrate the product for use in reactors -- those currently in operation and in the planning stages -- are considered adequate to meet growth forecasts.

Adoption of the Nuclear Waste Policy Act of 1982 will also tend to encourage growth, because the waste disposal problem has been considered a major uncertainty.

Thus, it appears that with a more favorable financial climate to encourage the necessary capital investments, electric utility and nuclear power growth will continue. However, regulatory delays in licensing remain to be resolved.

Spent Fuel and Wastes

Nuclear wastes are classified according to their source, form and degree of concentration of radioactive materials. The chief types involved in nuclear power production are low-level and high-level wastes.

Low-level wastes include clean-up materials, liquids, tools, machinery and other materials contaminated with low levels of radioactivity. Such wastes are buried in 55-gallon drums, 30 feet underground. High-level wastes are currently produced in the nuclear weapons program but will be associated with the civilian program if spent fuel from civilian reactors is reprocessed. Reprocessing yields valuable unused uranium and generates plutonium. It also results in some high-level liquid wastes that can be solidified and stored in underground repositories.

Some 75 percent of all low-level waste is of military origin, and, of the balance, about half comes from hospitals, educational and research activities. The remainder comes from nuclear power plants.⁷

In 1980, Congress passed the Low-Level Radioactive Waste Policy Act, which authorizes states to make regional agreements for locating waste burial sites. Six regional compacts are in various stages of formation.

High-level wastes result when spent nuclear fuel is reprocessed to yield plutonium. In 1977, President Carter deferred reprocessing as part of a plan to reduce the threat of proliferation of nuclear weaponry. (Plutonium is used in the manufacture of nuclear warheads.) The nation's commercial reactors have been storing their spent radioactive fuel in on-site underwater tanks while awaiting government policy on both interim storage of spent fuel and wastes and permanent disposal of wastes.

The waste problem was finally resolved when Congress passed the Nuclear Waste Policy Act of 1982. Under the new law, the Department of Energy will recommend three to five sites for interim storage facilities by June 1, 1985, and the President will select the first permanent geological repository by May 31, 1987. Public utilities will pay for waste transportation, interim storage and permanent disposal through a special pay-as-you-generate fee of one mil per kilowatt hour of nuclear-produced electricity. The new law also provides for emergency, short-term storage of spent fuel in the event some power reactors exhaust their on-site fuel storage space.

Resolution of the waste issue gives an important psychological boost to the nuclear power industry, because the move reaffirms the federal government's commitment to nuclear energy.

Licensing

Licensing of a power reactor has become an extraordinarily lengthy and involved process. A reactor must be licensed twice: first, to begin construction and then to begin operation.

The licensing process involves not only the filing of formal applications by the utility but also a lengthy review procedure by the Nuclear Regulatory Commission (NRC). This review includes further studies, conferences with the applicant and public hearings.

Siting and environmental factors contribute to the delays, in part because federal, state and local agencies often conflict in the many areas they regulate. A utility usually must obtain more than 50 permits to comply with federal, state and regional regulations.

As a result, according to the Department of Energy, it now takes 10 to 14 years to bring a nuclear power plant from initial planning to commercial operation.⁸ The impact of the cumber-

some review process is widely recognized within the government. President Reagan directed the Secretary of Energy to recommend improvements in nuclear regulation and licensing, "with the objective of shortening the time involved to 6-8 years, as is typical in some other countries."⁹

Early in 1983, both the Department of Energy and the Nuclear Regulatory Commission advanced proposals for streamlining the review process and simplifying regulation. While the proposals are not identical, they provide for pre-selected siting, giving the NRC the authority to approve a site for one or more nuclear power plants before a utility applies for a permit to build a plant. They also provide for issuance of combined construction and operating licenses, and the pre-approval of standardized plant designs.

The DOE proposal also addresses the problem of "backfitting" -- requirements by the NRC for safety changes in operating plants. Backfitting requirements, often costly, have been issued frequently by the NRC since the Three Mile Island accident. Under the DOE proposal, the NRC must determine that public safety will be "enhanced" by these requirements.

While the fate of these proposals in Congress is uncertain, nuclear power proponents consider them a positive sign that the long-standing regulatory problem is finally being addressed.

Nuclear Reactor Safety

The nuclear industry has an impressive safety record. In more than two decades, the AIF points out, no injury to the public has occurred, and no plant employee has been seriously injured by exposure to radiation.

Since the accident at Three Mile Island (TMI), government and industry have taken extraordinary steps to enhance plant safety and to guard against "human error" of the type that caused the TMI accident.

Reactor operator training, procedures and supervision have been upgraded, for example. Training programs focus heavily on improving the way operators "read" symptoms, particularly those leading to a potential loss of coolant.

The NRC has issued numerous technical regulations and proposed requirements, including costlier penalties for safety infractions and more inspectors for nuclear plant sites. TMI-related requirements will add about \$42 million to operating and maintenance costs for a new nuclear plant entering service in 1992.¹⁰

The industry is also now better organized to work on safety problems. In 1979, the Nuclear Safety Analysis Center, an arm

of the Electric Power Research Institute, was formed. In addition, the nuclear industry formed the Institute for Nuclear Power Operations (INPO) to step up the industry's self-regulation. Since early 1980, INPO technical advisors regularly have checked nuclear plants to help identify problems and to prescribe standards for improved operator and management performance. Nuclear power plants must belong to INPO to qualify for insurance that helps pay for substitute power in the event of an outage. All U.S. nuclear utilities belong to INPO.

The TMI accident also rekindled fears about the dangers of radiation.

A special presidential commission on the accident at Three Mile Island found that the public was exposed to amounts of radiation that were well within safe levels. The commission estimated that the radioactivity released to the 2 million people living within 50 miles of Three Mile Island was approximately 2,000 person-rem.¹¹ This works out to an average exposure of 1 millirem per person (0.001 of a rem) in the Harrisburg, Pennsylvania, area -- about the same as the additional natural background radiation a resident of Denver receives every week.

And a report on nuclear power plant safety released in March 1980 by a subcommittee of the House Committee on Science and Technology asserted:

The radiation exposure to the nearby population resulting from the accident at Three Mile Island was substantially less than that received from a number of other sources.¹²

In other studies, the health risks of nuclear energy have repeatedly been found to be minimal. In 1979, a committee of the National Academy of Sciences concluded that the public's exposure to radiation from the nuclear power program is "trivial" compared with that from medical and natural sources, posing no discernible health threat. And the U.S. Department of Health, Education and Welfare, now the Department of Health and Human Resources, after a year-long study, reported that the health impact of occupational radiation exposure in the nuclear industry "is in line with the risks associated with other industries generally regarded as safe."¹³

Court Decisions

Several U.S. Supreme Court decisions handed down in 1983 may have a significant impact on future reactor construction and operation.

In one case the justices unanimously rejected a proposal to force the NRC to consider potential psychological damage to area residents before it reopens the undamaged Three Mile Island Unit 1 plant. Had the court ruled otherwise, the hearings process for operating reactors would have become even more complicated than it is now, and the licensing delays might have been further extended.

In another case, the court decided that individual states may ban construction of future nuclear power plants if the lack of permanent federal waste disposal sites makes the plants uneconomic.

While some anti-nuclear groups claim the ruling might also apply to currently operating plants, the courts would have to rule separately on that point. The AIF, on the other hand, believes the ruling's effect will be sharply limited.

Since the ruling does not affect any of the power plants currently under construction, it does not have any bearing on projections of nuclear power output during the balance of the 1980s.

Outlook

Nuclear energy should grow steadily during the balance of the 1980s, despite the current array of problems.

Even with high interest rates and long construction lead times, nuclear energy still retains a cost advantage over coal, according to the AIF. Faster licensing procedures should help widen that advantage.

To a large extent, the industry's future will depend on the public's attitude toward nuclear energy.

William L. Rankin, a sociologist at the Battelle Human Affairs Research Center, assessed the results of 228 national, state and local public opinion surveys on nuclear energy conducted by various polling organizations over a number of years, and reported:

In general, there is presently still more support than opposition for constructing additional nuclear power plants in the U.S., but the support is significantly lower now and the opposition is significantly higher now than before the TMI accident.

. . . When given three alternatives to choose from, about a 45% plurality of the public favors operating only existing nuclear plants, about 30% favor building more plants, about 15% favor shutting down all plants, and the remainder are undecided.¹⁴

There are some indications that the more familiar people are with nuclear power, the more they are likely to favor it. In the state of Maine, for example, where consumers receive much of their electricity from the Maine Yankee nuclear plant, the voters in 1982 turned down a proposal to close the plant within five years. It was the second time Maine voters supported retention of nuclear power.

The "familiarity-favorability" thesis gains support from a survey of scientists, conducted by Stanley Rothman and S. Robert Lichter.¹⁵ The survey showed that while public support for nuclear energy has declined in recent years, the scientific community favors nuclear energy development by an overwhelming majority. The survey indicated that nine out of ten scientists believe the United States should proceed with nuclear development (53 percent favored proceeding rapidly). As for the reasons for their strong support of nuclear power, three out of four scientists regard the energy problem as "very" or "extremely" serious -- in contrast to general public perceptions that the energy crisis is over.

The rapid progress of nuclear power in other countries may eventually help foster an improved climate for growth in the United States. In France, nuclear energy now provides 38 percent of all electricity produced in the country. Switzerland, Sweden, Belgium, Taiwan, Finland, Japan and West Germany also currently lead the United States in terms of their reliance on nuclear energy for electricity.

With a climate of public acceptance, and timely government action on the spent fuel storage and licensing problems, by 1990 nuclear power could make a significant contribution to the national goal of reducing imports.

V. SYNTHETIC FUELS AND RENEWABLE ENERGY

In addition to oil, natural gas, coal and nuclear power, a new generation of energy resources will be contributing to U.S. energy security in 1990.

These new sources include oil and gas made from coal; oil from shale and tar sands; energy derived from the sun's heat (solar thermal) or from sunlight (photovoltaic); fuels from plant matter (biomass); and electricity generated from natural forces such as water, wind and the earth's heat (geothermal energy). Hydropower currently provides the largest supply of electricity from natural forces, although the growth potential of hydropower is less than that of other natural energy sources.

These alternative technologies now provide the nation with the oil equivalent of about 1.6 million barrels a day (1.5 mbde from hydropower and 0.1 mbde from other sources). World oil price reductions in 1981, 1982 and 1983 have slowed the pace of development of these technologies, clouding their short-term outlook. However, in the long term, America will increasingly rely on these alternative forms of energy.

The benefits of synthetic fuels development are far-reaching. Synthetic oil and gas can provide a critically needed supplement to petroleum reserves and, unlike some energy sources, directly replace -- barrel for barrel -- oil imports.

Resources for Synthetic Fuels

Fortunately, this country possesses the natural and technological resources to make solid progress on synthetic fuels during the 1980s. Coal and oil shale are the principal sources of synthetic fuels. The United States has recoverable coal resources of around 230 billion tons¹ and recoverable shale oil resources of about 600 billion barrels.² Together these resources amount to more than five times our total recoverable resources of conventional oil and gas.

Some technologies for these energy sources are already known and considered to be commercially feasible. The basic technology for extracting oil from shale is more than a hundred years old. The conversion of coal into synthetic gas began in

the 19th century. Coal was first made into oil in the early part of this century. Production of alcohol from biomass is one of the oldest arts, and the use of alcohol as a motor fuel dates back to the invention of the automobile.

Large-scale "synfuel" production, however, will require more than the revival of old technology. Government and industry have spent billions of dollars to research new methods of converting coal, shale and biomass into synthetic fuels. Oil companies particularly are involved in the development of shale oil, coal conversion and solar energy. Their research and development budgets and technical ability are helping to bring supplementary fuels to the point where they can start contributing to the nation's energy supplies in the 1980s and beyond.

Synthetic Fuels from Coal

A number of companies -- both oil and non-oil firms -- are researching methods for producing synthetic gas, methanol (a type of alcohol) and oil from coal. These technologies have been tested on progressively larger scales and a couple are in production at commercial scale -- for example, low-Btu gas and indirect liquefaction. The research of the 1980s will be devoted to developing coal technologies, including building pioneer plants with help from the U.S. Synthetic Fuels Corporation -- a government corporation established in 1980 to encourage synthetic fuels research and development. Much remains to be learned if these technologies are to compete with conventional oil and gas in the 1990s and beyond.

The basic technology for producing gas or liquids from coal is well-known. Coal is gasified by reaction with oxygen and steam to produce a mixture of carbon monoxide, hydrogen and other gases. Synthetic gas can be burned as fuel by industries and utilities, or it can be converted into nearly pure methane -- the major ingredient of natural gas.

Several methods exist for converting coal into liquid fuel: pyrolysis, direct liquefaction and indirect liquefaction. Pyrolysis applies heat to pulverized coal in order to break down parts of the coal molecules into liquids and gases. Direct liquefaction produces liquids from the interaction of coal and hydrogen at high temperature and pressure. Through indirect liquefaction, coal is converted to synthetic gas, and then the gas is catalyzed to produce hydrocarbons or methanol. Additional processing can convert methanol to gasoline.

Oil companies have been active in research and development of coal conversion processes. Two large coal liquefaction facilities in the United States are the H-Coal Pilot Plant in Kentucky in which Ashland Oil is a partner and operator and the Exxon Coal Liquefaction Pilot Plant (Exxon Donor Solvent) in Texas. Both plants have completed their project objectives. The Exxon Donor Solvent plant is being disassembled while the

H-Coal project may continue to be used for additional tests. These research plants, when operating, have produced about 550 barrels of oil products and 50,000 cubic feet of gas daily. Other oil companies are also moving forward on coal liquefaction processes.

Texaco and other investors are involved in a full-scale effort to test an electric power generating plant using gasified coal as the fuel. Located in Daggett, California, the Cool Water Coal Gasification Program would integrate a 1,000 ton-a-day gasifier using the Texaco Coal Gasification Process to produce approximately 100 megawatts of electricity. The project continues to move forward pending a contract to be completed by mid-1983 with the U.S. Synthetic Fuels Corporation for \$120 million in financial assistance. This system, scheduled to be completed by mid-1984, will be the largest electric power generating plant in the United States based on modern coal gasification technology.

A few coal gasification plants could be in operation by the mid-1980s. One of these is the Great Plains coal gasification project. This project is being constructed near Beulah, North Dakota, by a consortium of five partners, including one oil company, Tenneco. It will be the world's first coal-based synthetic natural gas plant. When operational in 1984, it will convert North Dakota lignite -- a low-grade coal -- into a cleaner burning, more easily transported fuel.

Fluctuations in the price of crude oil can affect the short-term outlook for synthetic fuels from coal, which must compete with conventional oil and gas. But in the long term, commercial production of synthetics from coal is likely to increase.

Shale Oil

The idea of producing oil from shale rock is not new. Shale oil production preceded crude oil production in the United States by several years. In the 1850s, some 53 domestic firms manufactured oil from eastern deposits of shale. Oil shale is a fine-grained, sedimentary rock that contains a solid substance called "kerogen."

While the basic technology for extracting oil from shale is more than a hundred years old, several oil companies have been investigating new shale oil processes over the past 20 years. For example, some companies have worked on "in situ," or underground, methods of distilling oil from shale deposits in Colorado. In these processes, a portion of the rock is mined and the rest is fractured and heated underground. The heat releases the oil which is piped to the surface. Chevron, Gulf,

Amoco, Occidental, Tenneco and Texaco are among the oil companies experimenting with new ways to extract oil from shale.

Some projects are already underway. Union Oil, for example, is constructing a plant in Garfield County, Colorado which -- when completed (scheduled for August 1983) -- will produce 10,000 barrels a day (bpd) of high-quality synthetic crude oil from shale oil. Operation of this facility will verify the technical, environmental and economic characteristics of a commercial-sized plant. Union proposes to expand its syncrude production capacity in increments of 20,000 bpd until a total capacity of 90,000 bpd is reached. However, reaching that objective depends on successful performance of the 10,000 barrels per day facility; acquisition of necessary federal, state and local government permits; and financial assistance from the U.S. Synthetic Fuels Corporation. The expansion will require more mines along with additional retorts (in which shale is heated to release raw shale oil), and facilities to upgrade the raw shale oil into a final syncrude product. The first 20,000 bpd capacity increment could be finished as early as 1989, with production of the full 90,000 bpd possible by the mid-1990s.

Mobil is currently planning for the development of its Parachute Shale Oil property. The project would achieve 100,000 barrels per day production some 15 years after the start of construction. Construction could begin anywhere from 1985 to 1988.

Phillips, Sun and Sohio expect to produce 14,000 barrels a day in their Utah White River plant by 1989, with production reaching 100,000 barrels a day shortly after the year 2000.

The Paraho-Ute Project in Uintah County, Utah, is being developed by the Paraho Development Corporation -- a joint venture that includes Texas Eastern Corporation and Sohio Shale Oil Company as sponsors. The group plans a surface retort system that will ultimately produce 39,500 barrels per day of hydrotreated shale oil. Construction is slated to begin in 1983, dependent on financing from the U.S. Synthetic Fuels Corporation. Oil production would begin in late 1985 on a reduced scale. And full production would begin in late 1990.

In Rio Blanco County, Colorado, the Cathedral Bluffs Shale Oil Company, a partnership between Occidental Oil Shale and Tenneco Shale Oil Company, is proposing a project to produce more than 10,000 barrels a day of upgraded shale syncrude.

Always in search of secure and independent sources of fuel, the military also has backed the development of shale oil. The Department of Defense (DOD) has been involved in shale oil production since World War I, when the government established a Naval Oil Shale Reserve near Rifle, Colorado. Over the past

six years, DOD has tested refined shale oil products as both aviation and ground transportation fuel. Thus, shale oil could play an important role not only as a commercial fuel but also as part of a military fuel reserve.

Tar Sands

Tar sands are sands found in their natural state saturated with heavy oil or tar. Where the sands are shallow, they can be surface mined and the oil recovered with heat. Where the deposits are deep, underground or in-situ methods must be used. One such method is to drill conventional oil wells and inject steam to melt the tar. Another method is to create an underground fire. In both cases, the liquid is then pumped to the surface through heated pipes.

The United States has considerable tar sands deposits -- exceeding our proved crude oil reserves -- but most of them are difficult to extract. Tar sands have been found in at least 22 states, although most are in Utah. Sohio has experimented with surface mining Utah tar sands. However, the majority of the deposits are deep enough to require the more difficult and expensive in-situ methods. The Department of Energy (DOE) has completed the third in a series of underground recovery field experiments on a Sohio lease near Vernal, Utah, and is planning several more. Conoco recently patented its "Fracture-Assisted Steam Technology" (FAST) for extracting the tar or heavy oil from tar sands. Conoco hopes to use the process in developing its 40,000 acre tar sands tract near Uvalde, Texas.

Standard Oil of California and GNC Energy Corporation are proposing a project to produce heavy oil from tar sands through mining and solvent extraction at the Sunnyside Tar Sands project in Carbon County, Utah. Plans are to upgrade the heavy oil using conventional refining techniques. The first phase would produce 1,600 barrels a day. The second phase would result in a commercial plant that would produce up to 36,000 barrels a day. Construction of the first phase would begin in early 1984 with the first production estimated for late 1985.

Production of oil from tar sands in the United States is not expected to be significant by 1990. In contrast, commercial production is already underway in Canada where the surface mining method is used extensively in the development of tar sands. Canadian tar sands development is ahead of U.S. efforts for several reasons. First, the United States has much smaller reserves than Canada, and only a small portion of U.S. reserves are recoverable by the surface mining method. Second, the U.S. surface-minable deposits are a different type of tar sands than Canada's, and separation of the oil from the sands requires a different process.

Biomass Conversion

Biomass is not only one of the oldest but also one of the most accessible sources of energy. Biomass includes every kind of organic substance that can be turned into fuel. Wood and dry plant or organic waste can be burned directly to generate heat and electricity. All organic matter can be converted into alcohol. Bacteria can break down organic wastes into methane.

Biomass conversion has unique advantages over most other energy technologies. First, the resources are renewable, unlike coal or petroleum. Second, conversion of municipal and industrial wastes into useful fuels can help solve two of the nation's problems simultaneously. It can both increase energy supplies and help clean up the environment.

At present, perhaps the most important biomass fuel is alcohol. A variety of alcohols -- including ethanol and methanol -- can be produced from plant and animal matter. Currently, distillers in the United States process ethanol from cornstarch, local waste, cheese whey, wheat and wood wastes. These liquids can supplement petroleum both as industrial feedstocks and as motor fuel.

Most manufacturers use ethanol derived from petroleum to make chemicals, solvents, detergents and cosmetics. However, before the growth of the petrochemical industry in the 1940s, manufacturers used ethanol made from biomass. Today, biomass-based alcohols once again are competing with ethanol made from petroleum. Nearly 30 percent of the alcohol used by industry is made from biomass. According to Information Resources Incorporated, if current trends continue, that market share could grow to 35 percent by 1985.³

The use of alcohols as motor fuel dates back to the 1880s, when some of the first automobiles ran entirely on ethanol. During the 1920s, farmers began to mix ethanol with gasoline. Gasohol -- a blend of 90 percent gasoline and 10 percent ethanol -- originally was called agrifuel, agrol or alky-gas. More recently, race car drivers have run their cars on methanol, and a number of fleet tests are underway using methanol as a motor fuel. Tertiary butanol (an alcohol) has been blended with gasoline by a number of companies for over a decade.

Alcohols are regarded as a significant supplement to gasoline for two reasons. First, efficiently produced alcohols can stretch supplies of motor fuel. Second, alcohols raise the octane rating of gasoline and, thus, can help refiners produce high-octane unleaded motor fuel.

Sales of ethanol blended fuels grew from 0.8 percent of total unleaded gasoline sales in 1980 to 1.5 percent in 1981 and 2.4 percent in 1982. Projections for 1983 are that over 4 percent, or more than 270,000 barrels a day of gasohol, will be consumed in the United States.⁴

Government and private industry are studying methods of boosting the production of alcohols so that gasohol and other alcohol fuels can contribute significantly to the nation's energy supply. Distillation methods in current use were developed in the 1930s and are being continually improved. Currently, the production of ethanol -- from growing the corn to distilling the final product -- can use more energy than it yields. If distillation methods improve, ethanol could be produced in a more energy-efficient way and thus make a greater contribution to our energy supply.

One step is to burn coal, wood or other fuels, rather than petroleum, in alcohol plants. For example, agricultural wastes could be burned as boiler fuel in stills. Scientists also are experimenting with different bacteria that could turn biomass into alcohol more economically than conventional processes.

Other biomass fuels, such as methane gas processed from plant matter and refuse, currently provide a negligible amount of energy. However, biomass gasification is a major area of research because methane produced from biomass could stretch supplies of natural gas. Interest focuses particularly on the conversion of municipal, agricultural and industrial wastes into methane that could readily replace natural gas in boilers and electric generators.

Questions have been raised about developing fuels from crops such as corn and wheat that are also needed for food. However, food and fuel need not compete if non-food crops are converted into energy. For example, some agricultural waste might be economically processed into fuel.

Also, Americans throw away at least 150 million tons of garbage each year. A considerable amount of this solid municipal waste could be converted into energy. However, there are now fewer than 30 such plants in operation in the United States. And less than 1 percent of the nation's municipal waste is now being used to generate energy. In contrast, Sweden, the Netherlands and Denmark convert 40 percent of their municipal waste into energy.⁵

A February 1979 General Accounting Office study estimates that by 1985 the United States could process 18 percent of the nation's garbage into energy. The study reports that municipal solid waste "could provide the nation with annual energy savings equivalent to 48 million barrels of oil."⁶

Geothermal Energy

Geothermal energy is produced from heat deep within the earth. Beneath the earth's surface is molten rock which, in some places, has pushed up close to the earth's crust. When underground water flows over these hot rockbeds, the water or steam rises through cracks in the earth. Geysers, such as Old Faithful in Yellowstone National Park, are a visible sign of geothermal energy.

Currently the major source of geothermally supplied electrical power in the United States is at The Geysers Geothermal Field in northern California. This field, where Union Oil has been the principal operator for more than 15 years, now produces about 12,000 megawatts of electric power -- sufficient power to meet most of the electrical demands of a city the size of San Francisco.

Geothermal operations are widespread in the western United States with activity in southern California, Idaho, Nevada, New Mexico and Utah. A 20-megawatt plant is being built in the Roosevelt Hot Springs area near Milford, Utah. In southern California, a major effort is underway around the Salton Sea area of the Imperial Valley to develop the hot geothermal brines located there. Two 10-megawatt demonstration plants have been operating in Brawley and near the Salton Sea. The plants are testing technology developed to deal with the hot brines characteristic of the area. The electricity produced from the plants will be used in the local area and is sufficient to serve a community of 18,000 people. The Salton Sea area is generally recognized as the "Saudi Arabia" of geothermal resources. These plants and others planned for the near future can add another 150 megawatts of generating capacity to the geothermal total.

Geothermal projects such as these still must overcome a number of economic and technical problems. For example, drilling costs in geothermal zones are twice as expensive as those for onshore oil and natural gas wells of equivalent depth. This is due, in part, to the geological and geophysical characteristics of these zones, including unusually hard rocks, very high pressures and temperatures, and corrosive minerals present in the underground fluids. Programs, undertaken both privately and in cooperation with DOE, are working to improve drilling technology, equipment and tools.

Nevertheless, the operation of The Geysers Geothermal Field and the numerous projects underway augur well for geothermal's role in helping to augment the nation's future domestic energy supply.

Renewable Energy Resources

Several forms of energy are classified as renewable resources. Renewables are those that derive energy from natural forces such as the ocean's tides, rivers, winds and the sun. Tidal and waterpower as well as wind power can generate electricity indirectly by turning turbines or fans. Two processes use solar power: solar thermal -- the use of the sun's heat for heating or cooling; and photovoltaics -- the conversion of sunlight directly into electricity by means of solar cells.

Solar Technologies

Solar thermal systems are the most developed and simplest of the solar technologies. Passive solar systems are architectural designs that take advantage of site and building materials to turn the building into a solar collector. In effect, the passive solar system is a form of conservation.

Active solar thermal systems involve mechanical moving parts. The basic unit is the solar collector -- a panel often made of aluminum, glass, plastic and copper. These panels, fitted to a roof, absorb direct sunlight and transfer heat to a fluid that passes through the collector. The fluid flows through pipes into the building, where it can be used to heat water, warm rooms or even provide heat for industrial processes.

The Department of Energy estimated that, in 1979, energy from solar collectors amounted to the equivalent of about 3,800 barrels of oil a day -- less than 0.02 percent of all energy consumed in the United States.⁷ DOE based its estimate on the 40 million square feet of known solar collectors then in use. By January 1, 1983, some 104 million square feet of known solar collectors were in use, and the number continues to increase.⁸

Economic factors will determine the extent of further increases in the manufacture of solar panels; new technology is required to lower costs and increase the competitiveness of solar thermal units. Also, increased production depends on the availability of aluminum, copper and other materials required to produce panels.

Photovoltaics -- solar cells -- are electrical "semiconductors" made primarily from silicon that convert sunlight into electricity. Although the photovoltaic effect has been observed for almost 140 years, the space program first developed the technology in the 1950s and 1960s. With the advent of the oil embargo and higher prices, research on solar cells by the private sector accelerated in the 1970s.

Because the materials are expensive, commercial production of photovoltaics is far smaller than that of solar thermal systems. In the past, the government heavily supported the industry through research grants and through purchases. Support has substantially decreased in recent years. Until costs are reduced, it is unlikely that photovoltaics will attain wide commercial use. Currently, electricity generated from photovoltaic sources is at least 10 times more expensive than conventionally generated electricity.

Despite the current impediments to commercialization, industry continues to fund research and development of solar technology. To date, for example, a conservative estimate of total oil company investment in solar energy -- both thermal and photovoltaics -- is more than \$100 million.

Some oil companies are engaged in photovoltaic and thermal development. Exxon, Arco, Shell (which recently formed a joint venture with Motorola, called Solavolt) and Mobil produce solar cells commercially. Phillips is involved in a venture, called ACUREX, for production of both thermal and photovoltaic systems. Exxon's involvement in solar cell research began in 1969. Before the 1973 oil embargo, the company's internal research and development funding for solar cell research was larger than that of the federal government.

The French petroleum company CFP-Total has majority interest in a photovoltaic plant in El Paso, Texas, and another French company, Elf Aquitaine, has announced that it will participate in the research, development and production activities of Photowatt International, a California-based firm. Chevron is funding photovoltaic research at the University of Delaware. And eight other oil companies have conducted research, been awarded solar patents, or are actually using solar power themselves on a small scale.

Since the oil embargo, some 249 firms that manufacture solar thermal systems have sprung up. Most of these companies are relatively small firms with annual sales of less than \$10 million each. Arco, through a subsidiary, is the only oil company that sells thermal systems commercially, although Chevron has announced plans to market a solar water heater. Exxon has recently moved out of the solar collector market by selling its "Daystar" subsidiary to American Solar King Corporation, a small manufacturer.

Hydropower and Others

Hydropower is an important resource that already contributes significantly to the nation's energy supply. Hydropower -- electricity generated by water as it falls and turns turbines -- supplies 1.5 mbde. However, the share of

conventional hydropower is not likely to increase markedly because sites for new dams are limited -- although interest is reviving in older, unused dams which could provide small amounts of electricity for nearby communities.

In addition to hydroelectric power, other natural resources, such as wind and tidal forces, could become sources of energy in the future. Scientists currently are conducting research on ocean tides, and the aerospace industry is investigating new methods of generating electricity from wind. However, these unconventional sources of energy will not offer significant contributions to domestic supply by 1990.

Getting Alternative Fuels to Market -- Problems and Opportunities

The 1980s will be a decade of transition for alternative fuels. Much will be learned about technical performance, costs and environmental and health effects as alternative fuels move from the research stage to the commercialization stage. Some processes now under study may never become commercially feasible, while others may have only limited value. What is learned in the 1980s will determine how large a contribution alternative fuels can make in the 1990s and beyond.

Market growth will depend on how the costs of synthetic and conventional fuels compare in the future. Because many synthetic processes have never been in commercial use, their costs, large-scale feasibility and environmental impact are difficult to assess.

The best approach to synthetic fuels development is to provide a stable business climate and investment incentives that let the market develop the most efficient, least-cost domestic energy sources generally. However, if for reasons of national energy security the nation wishes to accelerate synfuels development, programs can be established to attract investment specifically for that purpose. Logically, any such program would not commit consumers to any one process but would allow the market to select from among the competing technologies those best suited to the public's energy needs.

The government can help accelerate synfuels development through tax incentives and other actions. Tax incentives can improve the economics of investment in long-term, capital-intensive projects. However, any program to encourage synthetic fuels production should offer voluntary incentives and avoid mandatory production or consumption levels.

These kinds of tax measures, for example, would encourage synfuel development:

- Provide energy investment tax credits for synfuels.
- Provide tax credits for alternative fuel production.
- Allow companies to begin depreciating for synfuel development expenditures in the year that investments are made.
- Allow companies to deduct for expenditures mitigating community impact of synfuel development in the year those expenditures are made.

The 1980 Energy Security Act provided, among other things, for the establishment of a synthetic fuels corporation to accelerate the commercialization of synthetic fuels through a variety of incentives including loan guarantees, price supports and loans. In using these incentives, the U.S. Synthetic Fuels Corporation should:

- help pioneer plants achieve commercial production;
- assist a variety of technologies to help determine the most economic and environmentally sound approaches; and
- encourage efficient design and operation.

Government can also improve the atmosphere for synthetic fuels development by modifying some existing laws that may inhibit the development of these alternative fuels. For example, the same environmental restrictions that frequently delay conventional energy projects will impede the production of synthetic fuels from coal and shale.

In a report released in early 1980, the House Science and Technology Committee's Advisory Panel on Synthetic Fuels noted that the demonstration phase of a commercial synthetic fuels program can be operated in a manner "consistent with present substantive and procedural environmental laws."⁹ However, the panel suggests that wide-scale commercial development of synthetic fuels "may require some modification in those laws to meet particular problems."¹⁰

Modification of the Clean Air Act and its regulations, in particular, can cut the red tape and speed the process of review and approval required for synthetic fuels development. For example, the Environmental Protection Agency (EPA) originally refused permission to the Rio Blanco Oil Shale Company to build a shale oil plant in western Colorado because natural pollutants, such as dust, caused the air quality of the area to fall short of EPA standards. After monitoring the area for one year, Rio Blanco demonstrated that the EPA standards

were unrealistic. EPA reinterpreted its regulations on natural emissions and subsequently granted permission for the project.

Questions have been raised about possible unknown effects of synthetic fuel processes on human health. Government and industry are closely monitoring experimental work on coal conversion, shale oil and biomass. Much more will be learned before various synthetic fuels projects reach the commercial stage. But some of the data now available suggest that synthetic fuels development may pose fewer environmental hazards than anticipated.

The Federal Interagency Committee on the Health and Environmental Effects of Energy Technologies reported in 1979 that synthetic oil and gas from coal "may be environmentally compatible and clean burning."¹¹ The committee also stated that, while coal conversion may create health risks, "the actual hazards may be no higher than those from conventional coal or petroleum refining operations."¹²

Many uncertainties are present in the commercial development of new energy technologies. But the benefits to the public of developing alternative energy resources dictate that we press prudently ahead where controlled development is economically feasible. In the long term, these resources could provide an abundant, environmentally compatible and secure supply of energy.

VI. ENERGY CONSERVATION

Conservation is an important energy resource. Conservation is often thought of simply as using less, but it also means using energy more efficiently. In recent years, saving energy and using it more efficiently have helped substantially to reduce oil imports.

There is little doubt that Americans have been using less energy. One measure of energy conservation is the energy-GNP ratio -- how much energy is used to produce a dollar's worth of output (as measured by the gross national product, or GNP). In 1973, it took nearly 60,000 Btus to produce one dollar of GNP in the United States. In 1982, that figure was down to about 48,000 Btus -- a decline of 19 percent. (See graph, "U.S. Energy Consumption Per GNP Dollar.")

Between 1973 and 1982, U.S. energy consumption decreased 5 percent. Yet the level of economic activity, as measured by real GNP, had increased by nearly 18 percent.

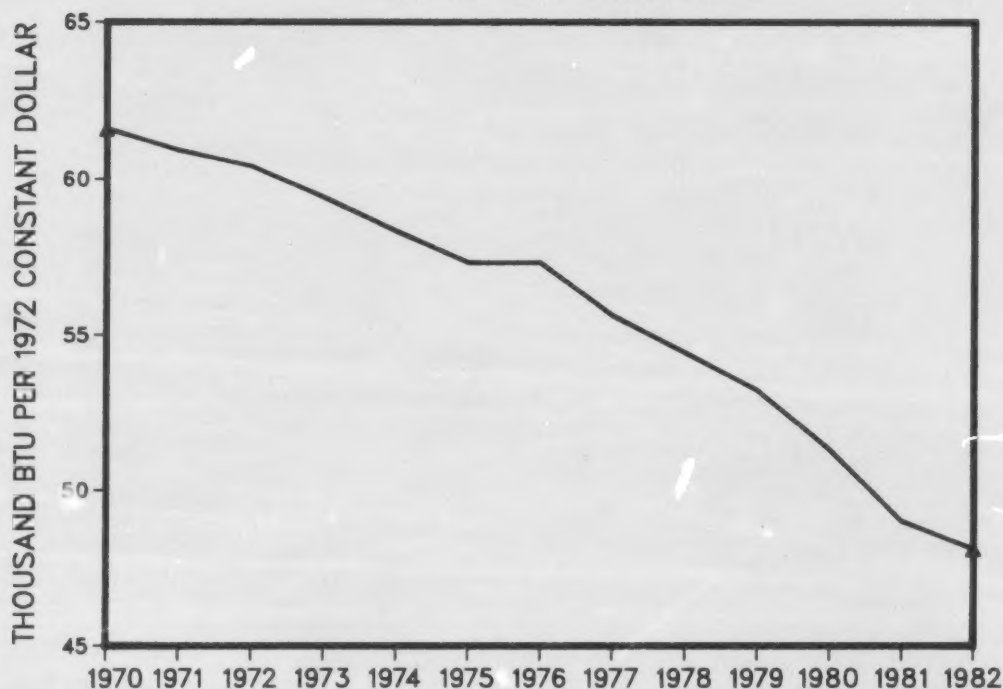
In short, energy consumption is well below estimates projected only a few years ago. These reductions have occurred because of past rising energy costs, intermittent cutbacks and embargoes of petroleum imports, and mandated fuel savings, such as the national 55 mile-an-hour speed limit. The recent recession has also contributed to reduced petroleum use, although to a lesser extent than many think. One recent study estimated that the recession was responsible for 24 to 29 percent of the total reduction in petroleum use in 1982.¹

The removal of federal price controls on crude oil, begun in 1979 and completed in January 1981, has been a major factor in the nation's remarkable progress in conserving energy. After growing steadily for 28 of the previous 31 years, oil use was down 2 percent in 1979, 8 percent in 1980, 6 percent in 1981, and 5 percent in 1982. Gasoline demand -- which had been growing about 3 percent a year -- began dropping by almost 4 percent a year in 1979. (However, the rate of decline has been slowing. In 1982, gasoline demand was down only 0.8 percent below 1981. And demand increased in the first quarter of 1983.)

Analysts now believe that the country will need about 12 million to 14 million barrels a day of oil equivalent (mbde)

less in 1990 than was projected only a few years ago. But, while the potential for saving energy and using it efficiently is great, it is not, of course, unlimited. The nation's overall energy needs are expected to grow, even though the rate of increase can be reduced through continued conservation. Many experts anticipate that the United States will still require from 13 to 22 percent more energy in 1990 than we used in 1982 to meet the needs of a growing population and economy.

U.S. ENERGY CONSUMPTION PER GNP DOLLAR in 1972 dollars



SOURCE: SEE APPENDIX

Thus, while it is not the total answer, conservation can continue to be an important response to the nation's energy needs. Because it has the effect of enhancing domestic energy security, conservation can be a key element in further reducing U.S. oil imports. To loosely paraphrase Benjamin Franklin, a barrel of oil saved is a barrel of oil that can be used in the

future. Government, academic and private research studies emphasize the importance of conservation in meeting future energy requirements. Indeed, conservation has become a widely accepted objective of national policy.

As has been clearly demonstrated in recent years, of all the energy options available to Americans, conservation can be a relatively direct route toward decreasing the nation's dependence on foreign oil. Through sound conservation policies and practices, the nation can significantly reduce the rate at which energy use rises, while still permitting long-term economic growth consistent with public expectations. And, by conserving, all Americans can help strengthen their country's energy position.

Effects of Conservation

Traditionally criticized as being energy-wasteful, Americans have been using energy far more carefully than in the past. During five of the last nine years energy consumption has actually declined.

During the post-World War II years and up to the 1973-1974 oil embargo, the average annual growth rate for energy use in the United States was about 3 percent.

Immediately following the embargo and subsequent quadrupling of world oil prices, total U.S. energy consumption declined -- dropping from 35.2 million barrels of oil equivalent per day in 1973 to 33.4 mbde in 1975.

As world oil prices stabilized in the mid-1970s and the U.S. economy recovered from the post-embargo recession, energy consumption rose again in 1976, climbing to 35.2 mbde -- the 1973 level -- and amounting to a 5.4 percent growth rate over the previous year.

After that one-year spurt, however, U.S. energy growth became more moderate. The increase in energy use was only 2.4 percent in 1977 and 1978 and less than 1 percent in 1979. Energy use actually declined from 1980 to 1982 by a total of 7 percent. This leveling off and decline came mainly in response to the sharp increases in world oil prices that resulted from the Organization of Petroleum Exporting Countries (OPEC) actions and the Iranian revolution. To the surprise of many, Americans demonstrated that they were capable of practicing conservation.

Recently oil has been in oversupply, and oil and gasoline prices have declined. Crude oil was down \$1.08 a barrel from March 1982 to January 1983. And gasoline declined 14.2 cents a gallon from March 1982 to March 1983. This is good news for

American consumers but leads some observers to be concerned that the trend to conserve will reverse. Complacency about oil supplies, Secretary of Energy Donald Hodel has warned, would be "like driving your car out of a service station after filling your tank and saying, 'Gee, I don't ever have to worry about gasoline again.'"²

However, several factors indicate that Americans are not likely to go back to their previous patterns of energy use. One reason is that many of the nation's conservation measures have become integral parts of the economy and society. For example, a higher percentage of motor vehicles have been manufactured to meet government gasoline mileage standards. This means that, as old cars are retired, there are more newer cars on the road that have greater fuel efficiency. Moreover, many of the conservation methods adopted by both consumers and industry are long-term in nature. More Americans now have storm windows, for example, and will not remove them just because heating oil prices might decline at a particular time. Many measures adopted by industry to produce greater output with the same or a lesser amount of energy will continue in place for sound business reasons -- the more energy-efficient an industry, the more competitive it can be.

The "Lag Effect" of Higher Energy Prices

This institutionalization of conservation practices is part of what economists call the "lag effect" of higher energy costs. One of the most significant, yet possibly least understood, aspects of today's energy situation is the delayed impact of the rise in energy prices that occurred during the 1970s. Even though much conservation has been implemented, it has by no means run its course. On the contrary, the conservation and efficiency effects stemming from overall higher energy costs are expected to continue to have an impact on the economy in years ahead.

This is because the total adjustment of energy consumption to a change in the price of energy takes place over a considerable time rather than instantaneously or in a single year. The immediate or short-run response to higher prices is apt to include relatively limited activities, such as turning down home thermostats in winter, driving fewer miles, driving at slower speeds and, in the case of industry, repairing capital goods such as boilers so that heat escape is reduced.

However, over the long run, the conservation response will be greater. Energy prices will continue to induce technological innovations aimed at reducing energy use. The stock of automobiles, houses, buildings and other capital goods will gradually be replaced by models that use energy less intensively.

Changed Projections

Over the last five years, projections for total U.S. energy consumption in 1990 have dropped by about 25 percent because of higher prices and conservation efforts. World oil prices are still much higher than before the OPEC price hikes of the 1970s and the Iranian cutoff. Therefore, there is still considerable economic incentive to conserve energy. Even if energy use should rise again during the 1980s -- and it is expected to -- forecasts suggest that the future increases in energy use will be less than those we have experienced historically.

The 1982-1983 forecasts for 1990 show an increase in consumption from the 1979 level ranging from 700,000 barrels a day of oil equivalent to 3.5 million barrels a day. Thus, current estimates project total energy consumption ranging from 38.0 million to 40.8 million barrels a day in 1990. This compares with 1990 consumption estimates of 50 million to 55 million barrels a day of crude oil equivalent made just a few years ago.

However, there are limits to the amount of energy that can be saved. Even the most efficient car will need some fuel. Energy requirements in homes and industries could be cut by as much as half, but homes and industries will still need natural gas, oil, electricity and coal. Therefore, while serious conservation will continue to be a necessary part of the effort to make the United States more energy self-sufficient, the vigorous development of domestic energy resources is also essential.

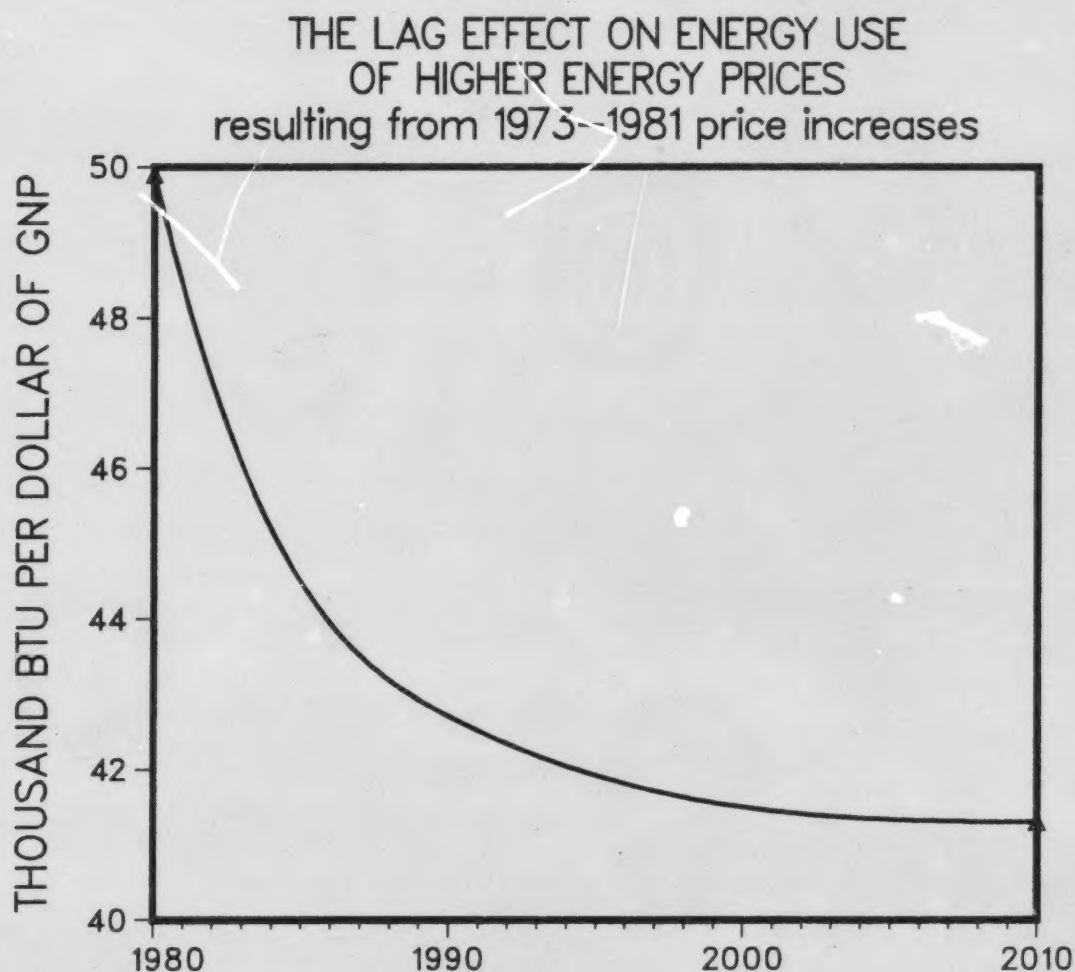
Public Information Programs

Both government and the private sector have expanded efforts to encourage public conservation of energy.

Many corporations, trade associations and private research groups regularly promote conservation measures. These range from urging motorists to save gasoline to special publications and seminars that offer tips on car maintenance, home insulation and good driving.

A number of companies also are subsidizing van pooling and mass transit commuting. Some oil companies and utilities provide residential energy audits for their customers to show where additional savings can be achieved through better insulation, heating systems or energy use practices. At least one company is offering, at cost, timing mechanisms that automatically raise and lower home thermostat settings. Others are underwriting an information-gathering program on energy conservation by the Carnegie Institute. And one oil company loaned a department manager to the city of Los Angeles to help form a car pool information program.

Thus, with the passage of time, the total response of energy consumption to higher energy prices will be greater than the response which takes place, say, in one year. According to one study, if energy prices were to remain constant from 1982 on, the full impact of the energy price increases that occurred from 1973 to 1981 would not be fully reflected in patterns of energy use until the year 2010. (See graph, "The Lag Effect on Energy Use of Higher Energy Prices.") Thus, the long-term adjustment would last for 37 years, reducing the energy-GNP ratio by 30.5 percent -- nearly one-third -- during that time.³



SOURCE: SEE APPENDIX

Information can also help consumers who are not able to determine on their own the energy efficiencies of goods they purchase, such as houses and appliances. To this end, mandatory efficiency labeling has been proposed. Although some manufacturers already provide such information, there are differences of opinion on the wisdom of mandating labeling.

Where the Biggest Energy Savings Can Be Made

Two major areas where additional advances in energy conservation can be made are homes and automobiles. (See graph, "Energy Consumption by End-Use Sector.")

Nearly 30 percent of U.S. energy demand occurs in the form of direct consumption for personal use, namely household and transportation fuels. Home heating accounts for about 11 percent of total U.S. energy consumption, while private passenger cars account for about 12 percent.

Residential

The number of homes will increase by an estimated 35 percent by the year 2000, so conservation measures in new as well as existing homes will be especially important. One authoritative study has projected that the number of homes in the United States will grow from 80 million in 1980 to 108 million by the turn of the century.⁴

The administration of President Carter estimated that well over 500,000 barrels of oil per day could be saved through residential conservation alone during the 1980s.⁵ Much oil conservation has already come about because of fuel-switching. From 1979 to 1980, for instance, conversions from home heating oil to alternative fuels reduced oil use by 35,000 barrels a day, and the pace of conversions continues to increase.

Home heating accounts for more than 50 percent of all residential energy use. Thus, significant energy savings could be achieved through:

- improvements in housing shells (in the form of better insulation, weather stripping, caulking and storm windows);
- more efficient heating systems in new housing and replacement of older heating units (for example, heat pumps to replace conventional electrical resistance heat systems); and
- improved house designs and layouts (for example, double-wall construction, the addition of vestibules, and windows facing south).

The staff of Resources for the Future (RFF), an independent organization for research and education in the development, conservation and use of natural resources, has examined home energy uses. RFF found that it would be cost-efficient to reduce the energy consumption of many homes by 45 percent.⁶ Further, the organization projected that energy requirements for home heating will decline slightly by the year 2000 despite a substantial increase in the number of dwelling units.

RFF also noted that major energy savings could be achieved to reduce total household energy consumption in the years ahead with little or no effect on individual life-styles or projected home construction.⁷

Automotive

Conservation obviously is important in the transportation sector. Energy used in transportation -- almost entirely from oil -- has accounted for about one-fourth of the nation's energy consumption in recent years. And private passenger cars account for about 50 percent of the transportation sector's energy demand.

Current government standards require the fuel economy of new automobiles sold in 1985 to average 27.5 miles per gallon. Additional reductions could be achieved if the public should voluntarily cut back its use of automobiles even further and make wider use of commuter car and van pools.

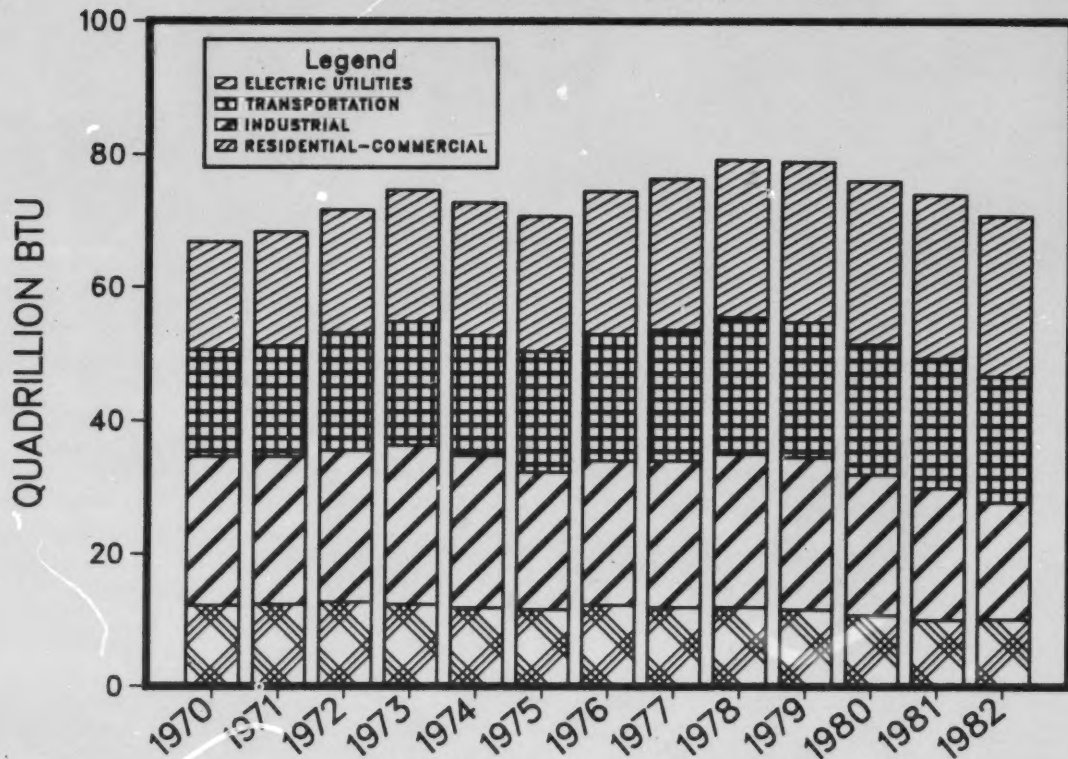
Compared with other industrialized countries in Western Europe and Japan, the United States uses energy for automotive transport more intensively. The causes are easily identified. Gasoline prices have been significantly higher abroad, largely because foreign governments have imposed stiff taxes on gasoline to raise revenues. Many of the countries also impose high taxes on cars, thus discouraging automobile ownership. In addition, public transportation in other countries is more developed and widely used because fares are subsidized and cities are denser.

Energy Conservation by Industry

Since 1972 -- the last full year before the 1973-74 oil embargo -- business and industry in the United States have become much more energy-efficient. Such savings are part of a recognition that energy conservation can benefit both stockholders and the general public.

Conservation by business and industry has been, in large part, a free market response to increased prices. In 1974, for example, U.S. petroleum refiners voluntarily decided to improve energy efficiency in refineries by 15 percent by 1980.

ENERGY CONSUMPTION BY END-USE SECTOR



SOURCE: SEE APPENDIX

By the end of 1977, the refiners already had surpassed the 15 percent mark, which in the meantime they had raised to a new goal of 20 percent. By the end of 1981, these refiners had achieved their goal.⁸

These savings have been achieved through better training, better "housekeeping" features and capital investment in equipment such as improved instrumentation, heat exchangers and pre-heaters. (A pre-heater is a type of heat exchanger in which a liquid or gas being fed to a process is pre-heated, using steam or one of the hot liquids or gases leaving the process.)⁹

In all, 10 industries were required to report energy efficiency progress to the government. By 1980 these industries had exceeded the original 1980 target of a 13 percent increase in efficiency by reaching a level of nearly 18 percent for the group.¹⁰

Substantial additional energy savings could be achieved in certain industrial processes, as well. Energy used to generate industrial steam, for instance, accounts for about 14 percent of total U.S. energy consumption.¹¹ Fuel consumption in this category could be reduced by employing what is known as cogeneration -- the combined production of electrical or mechanical energy and heat. The most common example of cogeneration is a boiler-turbine combination that provides both steam and electric power.

Conclusion

As the removal of federal controls on crude oil prices has shown, steps that promote a free market in energy can result in conservation gains. Former Secretary of Energy James B. Edwards stated, "Production is one pillar of our energy policy and conservation is the other. The free market is encouraging Americans to conserve."¹²

An effective conservation incentive program should be simple, market-oriented and encourage widespread participation, while minimizing the costs to the taxpayers. Under normal circumstances, individuals can best determine the appropriate amount of energy conservation. However, oil imports may pose certain national security risks, and hence some government incentives may be appropriate to encourage energy conservation beyond what would occur in free markets. Such government incentives should be analyzed to assure that the benefits to the public in terms of enhanced security outweigh the costs.

In summary, energy conservation can contribute substantially to further reducing the nation's dependence on imported oil by 1990. Evidence from recent years shows that voluntary energy conservation in response to price changes has been significant.

Step-by-step crude oil price decontrol moved the country in the right direction. Oil decontrol has induced energy conservation and has encouraged energy production, proving that decontrol works. There is every reason to believe that decontrolling natural gas prices, which have been under federal controls for almost three decades, would also encourage the more efficient use and output of natural gas.

Considering the impact of conservation, the consensus of "best case" energy forecasts is that, in 1990, U.S. energy requirements will be in the neighborhood of 38 million to 41

million barrels a day of oil equivalent -- as mentioned, 12 million to 14 million barrels a day below earlier projections.

But if conservation is to become a lasting way of life for Americans, realistic and reasonable energy policies will have to be pursued. Through additional efforts, conservation could well contribute still further toward cutting imports. How much more conservation contributes will depend on voluntary savings of energy by Americans and the policies adopted by government.

VII. ENERGY AND THE ENVIRONMENT

Ikebana is the practice of a centuries-old Japanese floral art form. It involves the esthetic arrangement of three basic lines represented by branches or stalks of different lengths. The longest branch represents the heavens, the next longest symbolizes earth and the shortest depicts man.

Ikebana strives to create harmony amongst heaven, earth and man in consonance with a chosen thematic order of their relationships.

A search for this same kind of harmony must underlie our nation's approach to resolving the energy and environmental problems of the '80s.

In striving for such harmony over the last 10 to 15 years, the federal government responded to public concern over environmental pollution with a series of major environmental laws. As a result, the United States has made rapid progress toward meeting the high environmental goals established by its citizens.

Further environmental progress can be made. But the nation must also continue recent progress toward reducing our heavy dependence on insecure supplies of foreign oil by increasing the development of our own vast energy resources. For at least this decade, the nation's conventional energy resources -- oil, natural gas, coal and nuclear power -- will be called upon to furnish most of the country's energy requirements. Later, unconventional sources will begin to play a substantial role in meeting the energy needs of American consumers. All of these resources can be developed with careful regard for the environment as we strive for harmony in achieving energy and environmental goals.

Significant Environmental Progress Has Been Made

Joseph Cannon, Associate Administrator for Policy and Resource Management of the Environmental Protection Agency (EPA), commented in the EPA Journal on the nation's environmental progress:

I doubt that anyone could deny that the present situation is encouraging to the notion that a large

industrial nation can succeed in cleaning its own house. The gross and obvious pollution that plagued us a decade ago is largely gone. The number of days of unhealthy air in major cities has declined virtually without a break since 1974. Despite growth in population and gross national product the U.S. Geological Survey reported no decline in water quality over the past several years. Important rivers have shown remarkable come-backs; we are seeing game fish in places they have not inhabited for a generation.¹

During the last decade, both air and water quality have been dramatically improved.

Improvements in air quality:

- Man-made emissions of particulate matter (dust, soot, etc.) decreased approximately 55 percent between 1970 and 1980 due to the control of industrial process emissions.²
- Average sulfur dioxide levels in urban areas decreased 24 percent from 1974 to 1980. Estimated sulfur oxide emissions declined approximately 15 percent from 1970 to 1980; the 15 percent reduction in emissions has been achieved even though the amount of fossil fuels burned increased by 10 percent since 1970.³
- Average lead levels in the air decreased 54 percent between 1974 and 1980; lead consumed in gasoline declined 62 percent.⁴
- Automobiles produced in 1980 emitted 90 percent less hydrocarbons and carbon monoxide and 75 percent less nitrogen oxide than models produced in the 1960s.⁵

These improvements and others have broken the link between industrial growth and air pollution (See graph, "Energy, Industrial Growth and Air Pollution.")

Improvements in water quality have resulted in the recovery of many of the nation's rivers and lakes:

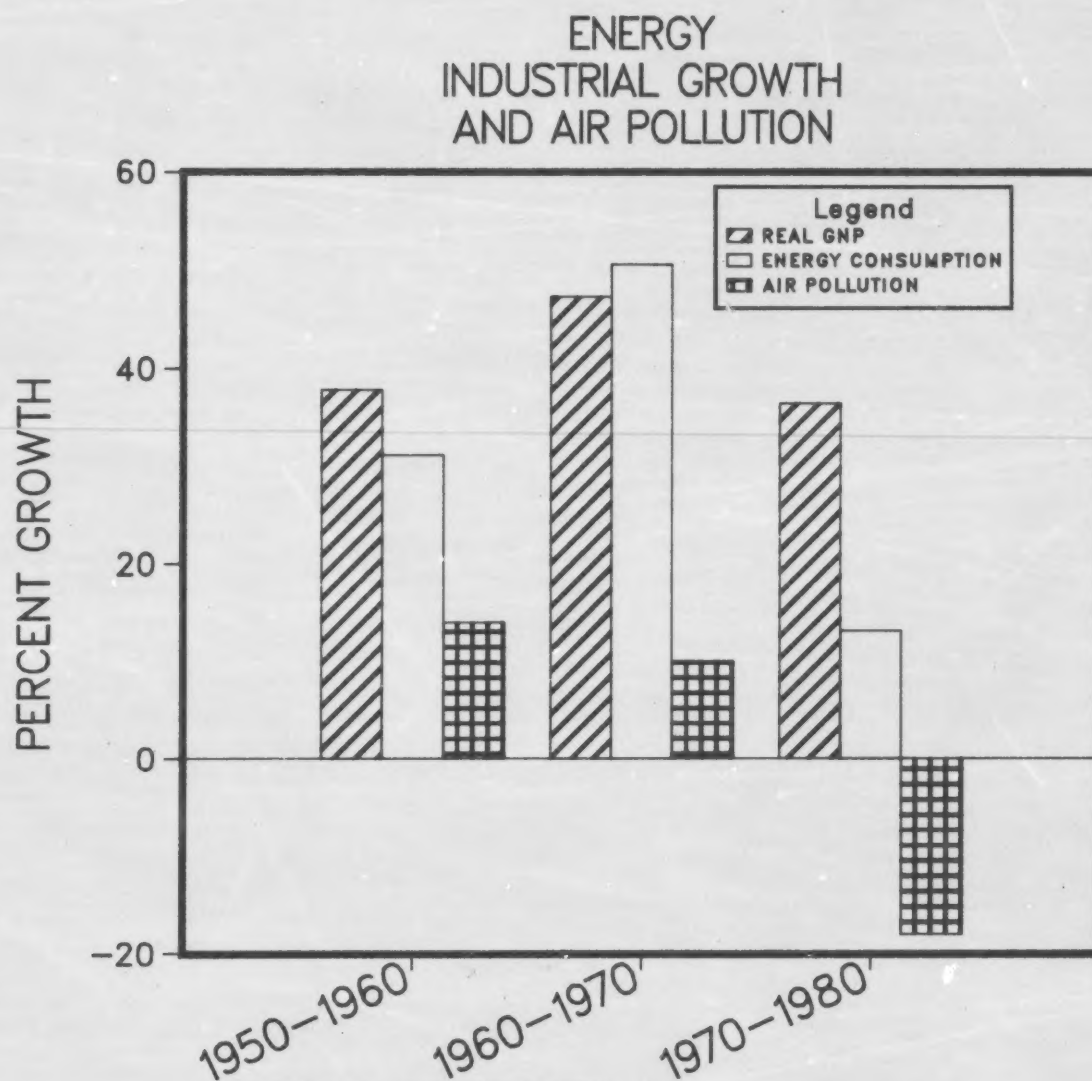
- Lake Erie, pronounced dead a decade ago, is alive with fish.
- The Hudson River, once badly polluted, has also been restored and beaches have been reopened.⁶
- Cleveland's Cuyahoga River, which once was so badly polluted that it burst into flames on a hot day, also now sustains fish.⁷

- The Delaware River, which at its worst ran black and emitted a foul stench, no longer offends the eye or nose -- in fact, much of the river meets the Clean Water Act's fishable and swimmable goal.⁸
- Boston's Charles River has also been significantly improved; canoes and sailboats frequent the river and fish are abundant.⁹
- The Willamette River in Oregon, the Penobscot and Winooski Rivers in the Northeast, the Great Lakes in general, the lower Savannah and Chattahoochee Rivers in the Southeast and the Potomac River south of the nation's capital -- all have improved substantially in the last 10 to 20 years.¹⁰

The petroleum industry itself, in responding to environmental concerns and regulations, invested over \$24 billion in air, water and land environmental improvements and research from 1972 through 1981.¹¹ Examples of the industry's progress include:

- reductions in emissions and odors at refineries through installation and operation of new equipment and procedures;
- development of improved technology to produce large quantities of low-sulfur heating oil and residual fuel oil;
- creation of systems used in refinery cooling and processing that draw water from a river or stream and then return it in the same or an improved state of purity;
- reduction of refinery discharges of conventional pollutants -- biochemical oxygen demand, suspended solids, oil and grease -- by more than 90 percent between 1967 and 1979;
- reduction of refinery discharges of toxic pollutants to near or below the lowest detectable levels;
- development of oil spill prevention, control, cleanup and monitoring methods and technologies to minimize adverse effects on the environment;
- establishment of two multimillion-dollar compensation funds to reimburse victims of oil spills from tankers; and
- development of sophisticated equipment and procedures to prevent or control blowouts from offshore petroleum operations.

The environmental laws adopted in the 1970s -- together with the efforts of concerned individuals and groups in both public and private life -- have moved us well along toward the goal of a cleaner environment.

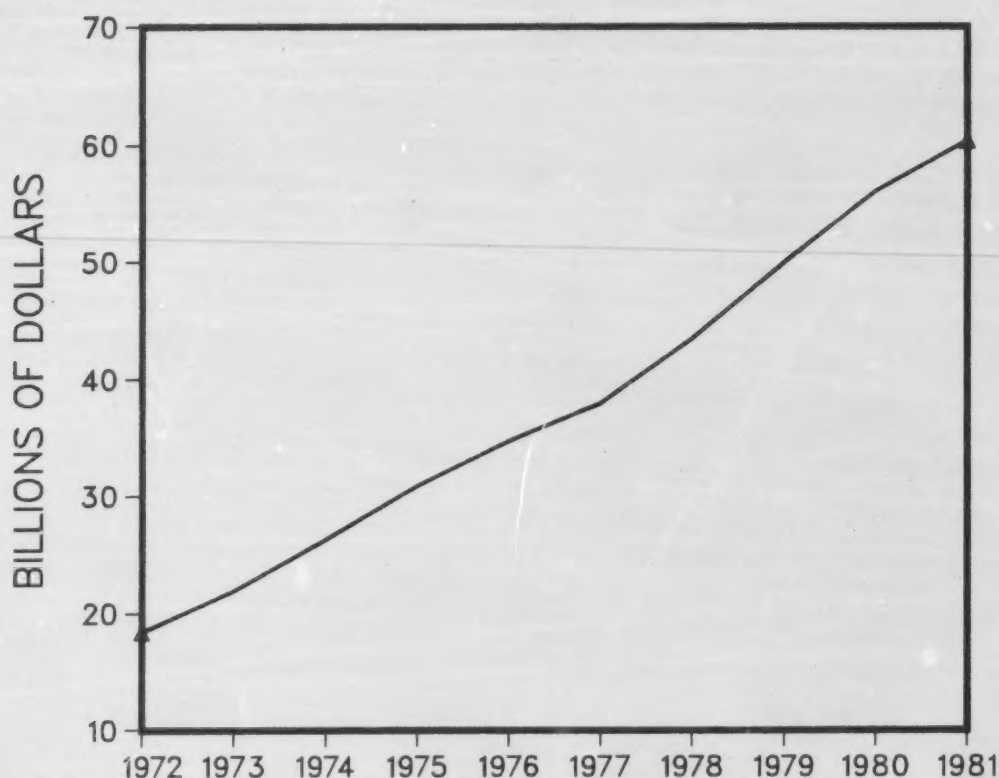


SOURCE: SEE APPENDIX

The Question of Economics

Gains on the environmental front have not come cheaply. According to the Bureau of Economic Analysis, from 1972 to 1979, the bill for pollution abatement and control increased steadily, with the total for that period exceeding \$260 billion (before adjusting for inflation). In 1981 alone, the bill was more than \$60 billion.¹² (See graph, "Pollution Abatement and Control Expenditures.")

POLLUTION ABATEMENT AND CONTROL EXPENDITURES in current dollars



SOURCE: SEE APPENDIX

The Council on Environmental Quality projects that during the 10 years from 1979 to 1988, total spending to comply with federal environmental quality regulations will total \$518.5 billion (in 1979 dollars).¹³

Joseph Cannon, EPA Associate Administrator for Policy and Resource Management, comments, "The issue is not the sheer magnitude of the costs but the fact that they should be explicitly considered -- we should know what we're buying, and at what price."¹⁴

This always valid point increases in importance with time because further cleanup achievements may be especially expensive. As EPA's Joseph Cannon explains, describing a graph:

As we begin to put on pollution controls we generate a curve. At first it is pretty flat -- we're taking out a lot of gross pollution and achieving a good deal of environmental protection for each increment of cost. In the middle of our scale the curve begins to rise: the cheap gains are over -- it costs more to pick up each additional point of score. Later the curve heads up sharply and eventually it's pointing nearly straight up. The marginal dollar is buying almost nothing.¹⁵

Lester Lave, a Carnegie-Mellon University economics professor, explains it this way:

It costs as much to go from 95 to 97.5 percent control of pollution as it did to get to the 95 percent removal stage. In order to go that extra increment, you have to install new technology.¹⁶

It should be noted that not all additional cleanup efforts would be represented by a sharply increasing cost curve. But many would -- especially considering the fact that some environmental laws require 100 percent control of pollution.

Clearly, as we continue to improve the environment, the measurement of costs and benefits can provide valuable information on the relative economic effects of proposals and their alternatives. A Washington Post editorial commented:

The benefits of pollution control are very substantial, but it's worth keeping an eye on the costs as well. Among the defenders of the present environmental protection laws it is frequently regarded as irrelevant, not to say immoral, to add up the economic costs of a good cause. But the patterns that emerge provide a reliable guide to choices that have to be made. And the amounts at issue are not small.¹⁷

The Time for Regulatory Improvement Is Now

Virtually all of the environmental control strategies in place today are based in large part on environmental legisla-

tion and regulation written during the 1960s and 1970s. If the nation is to deal effectively with the environmental problems of the 1980s, some of these laws must be modified. The Council on Environmental Quality noted in its 1981 annual report:

Many of the laws passed during the 1970s introduced the federal government into new areas of natural resource management; it is not surprising, therefore, that several years' experience with that legislation has shown that it imposed unforeseen costs or that it failed to address unforeseen problems. The rigidity and complexity of recent environmental regulations have hindered the nation's traditional ability to respond flexibly to an evolving value system with evolving institutions.¹⁸

The intent and goals of these laws often were good. But, the restrictions and red tape built into the laws and regulations work against development of much of the nation's vast energy resources.

Our nation is now at a critical point in the development of energy sources for the 1990s and beyond. The American public can experience continued environmental progress and have the additional domestic energy it needs -- from conventional and unconventional sources -- if government modifies environmental policies. Government can:

- Review and adjust environmental rules and standards that have unforeseen, unintended and unnecessary adverse effects on energy development and economic stability. For example, the Clean Air Act, as it now stands, subjects portions of the country to extremely limited-growth and, in some instances, no-growth policies. Unless the act is modified by Congress, it will retard the development of various forms of energy from coal to geothermal power and hinder industrial expansion.

- Eliminate the delay and uncertainty caused by the complexity of regulatory requirements. In some instances under the Clean Air Act, a proposed new energy project -- before it can move forward -- must survive 37 specific "yes or no" decisions and 24 chances by government agencies to slow down or stop the project altogether. Delay, which has not necessarily resulted in better decisions, has led business to withdraw applications or abandon proposed projects.

- Consider economic and social factors, as well as environmental concerns, when developing regulations that affect energy development. Government agencies should be required to conduct an economic assessment that includes the impact on energy development for all proposed major standards and regulations.

• Set realistic schedules and deadlines for achieving standards. Current deadlines require the states to attain the standards by specific dates. In many cases, however, the deadlines are unrealistic and burdensome because the technology is not yet available to reduce pollution to required levels by the required dates.

Prompt government actions to make environmental policies more flexible can lead to substantial new energy production including:

- the production of additional supplies of domestic oil and gas both onshore and offshore;
- the increased capacity to mine and use our abundant coal supplies;
- the eventual development of vast deposits of oil shale in the western states; and
- the conversion of portions of our huge reserves of coal into synthetic oil and gas.

The petroleum industry is working and planning now to meet the energy demands of the next decade. For oil and gas, new and advanced recovery techniques are being tried. For increasingly remote and hostile areas, new production technology is being researched and tested. These development activities are vital now, because large energy projects have long lead times.

For synthetic and alternative fuels, pilot and demonstration plants are being tested while larger plants are being designed or are contemplated. However, available technology and economic conditions, along with environmental restrictions, will determine when these resources will be competitive with conventional fuels.

Current Issues

Both the Clean Air and Clean Water Acts await reauthorization and amendment in the 98th Congress. This process could become even more complicated by two other issues whose causes are not clearly defined. Of concern are the ecological and public health effects of acid rain and groundwater contamination.

The Clean Air Act

The Clean Air Act, enacted in 1963 and amended on several occasions, most substantially in 1977, directs the Environmental Protection Agency (EPA) to set primary and secondary National Ambient Air Quality Standards (NAAQS). The purpose of

the primary standards is to protect public health with an adequate margin of safety. The secondary standards are designed to protect the public welfare, meaning such values as property and aesthetics.

The act set a 1982 deadline for attainment of the ambient air standards for seven air pollutants. However, states can receive a five-year extension of the deadline for two pollutants, carbon monoxide and ozone.

Areas of the country which do not meet federal air quality standards are designated nonattainment areas for that pollutant. Areas with ambient air quality better than that established by a national primary or secondary standard are designated Prevention of Significant Deterioration (PSD) areas for that pollutant. Some areas of the country are attainment for some pollutants but nonattainment for other pollutants. This causes overlapping requirements in these areas and complicates the administration of permitting.

National Ambient Air Quality Standards. Some of these standards are based on studies done as long as a decade ago. They do not reflect the extensive research conducted since then. Moreover, these standards do not reflect an adequate assessment of the quality or significance of the studies they were based on.

In addition, secondary standards, which protect values other than health, currently must be set on a national basis. However, regional standards that consider marginal costs and benefits would work better. For example, a very stringent standard might be appropriate for a largely agricultural state or region where the benefits from increased crop yields greatly outweigh the costs. But the same standard applied to a highly industrial area might not be appropriate.

Therefore,

1. A qualified scientific body should evaluate the air quality standards and the scientific basis for the studies that support them.

2. Secondary standards -- which are not health-related, but which protect other values such as property and aesthetics -- should be based on the marginal costs and benefits and take into account regional differences.

Nonattainment Areas. In nonattainment areas, EPA established and Congress put into law the emissions offset ruling to provide a means for growth while progress toward attaining the standards continues. Under the "offset policy," no major new sources, (that is, plants, factories, etc.) or modifications of

existing sources can be built in nonattainment areas unless the increase in emissions, even after complying with the lowest achievable emission rate requirement, is more than offset by a reduction in emissions from existing sources in the same area. In other words, before a new facility can be approved, the applicant must find ways to eliminate more air pollution than the new facility would emit. However, emissions offsets are becoming increasingly difficult to locate and acquire, thus making it difficult to secure permits to construct or modify facilities in nonattainment areas.

The act provides for severe sanctions if federal air quality standards were not met in nonattainment areas by the end of 1982. The sanctions ban new construction regardless of how the construction affects the area or whether the nonattainment problem can be reasonably solved over time. In addition, other states without established motor vehicle inspection and maintenance programs are subject to a cutoff of federal highway funds.

Many areas of the country failed to meet the standards by the deadline. In February 1983, The Washington Post reported that the Environmental Protection Agency had warned 213 counties and the District of Columbia that they may face bans on certain kinds of industrial construction and lose federal highway funds for violating the Clean Air Act.¹⁹ The imposition of the construction ban could cause significant harm to employment and local economies.

For these reasons,

1. States that make good-faith efforts but cannot meet the deadlines for attaining the standards should be able to set later deadlines if progress continues.
2. Government review of proposed energy projects should balance the need for emissions offsets with the need to reduce oil imports and maintain a sound economy.
3. The construction ban should be eliminated because it is ineffective in improving air quality.

PSD Areas. Prevention of Significant Deterioration (PSD) regulations apply in areas of the country where air is cleaner than required by the National Ambient Air Quality Standards (NAAQS). PSD regulations impose a ceiling on the cumulative increase ("increments") allowed for sulfur dioxide and suspended particulate matter. The precise size of the allowable increments will vary, depending on whether the area in question is classified as Class I (where the most stringent requirements apply), Class II or Class III. Large national parks, wilderness areas and other specially designated areas

are Class I. Most other clean air areas of the country are currently designated as Class II. Still other areas may be designated as Class III to permit additional economic development, but the procedural obstacles are substantial and no areas have been so designated to date.

Every project subjected to the PSD review must meet pre- and post-construction air quality conditions through extensive air quality monitoring and computer modeling and must provide for installation of best available control equipment sufficient to satisfy EPA. The pre-construction permit process can delay development for several years.

In attainment areas, the current PSD increment system, along with provisions to protect visibility, appears certain to constrain future energy development.

For these reasons,

1. The current system for protecting clean air should be replaced with requirements for use of the "Best Available Control Technology" (BACT), and a review to ensure that the national ambient air standards will not be violated.

2. In special areas such as national parks or forests, there should be an additional review to protect the special environmental values.

3. No visibility requirements should be imposed until an adequate way to predict and measure visibility impairment is developed.

The results of case studies completed by API suggest that production of fuels from unconventional sources could be increased by more than one million barrels per day with constructive changes in the Clean Air Act. According to the studies, if economic conditions were favorable, such changes could result in 350,000 barrels a day more heavy oil output, 400,000 barrels a day more shale oil production and 320,000 barrels a day more coal-based synthetics by 1990-2000.²⁰ Because these case studies looked at only particular regions and types of projects, the total effect of Clean Air Act changes could be even greater. These increases could be achieved while still attaining National Ambient Air Quality Standards and protecting air quality in areas with unique scenic values, if the Clean Air Act is modified.

The Clean Water Act

Enacted in 1972 and amended in 1977 and 1978, the Clean Water Act calls for the attainment of "fishable and swimmable" waters where possible by 1983 and the elimination of the discharge of pollutants ("zero discharge") by 1985.

The Clean Water Act is up for review and reauthorization in the 98th Congress. A re-evaluation and revision of some of the act's provisions could lead to improved, cost-effective approaches while still maintaining progress toward the objectives of the act.

Certain provisions of the act can hinder energy development without necessarily contributing to cleaner water. Specifically, the act should be modified in these areas:

Effluent Limitations and Guidelines. The Clean Water Act requires EPA to develop effluent limitations controlling the discharge of pollutants from industrial facilities. Industry must comply with limitations requiring the application of Best Available Technology (BAT) and Best Conventional Technology (BCT) no later than July 1, 1984.

This deadline needs to be extended. Insufficient time remains before July 1, 1984, for authorities to promulgate BAT and BCT guidelines and incorporate limitations into discharge permits and for industry to design, purchase and install any necessary technology to comply with the limitations. EPA will not even have promulgated BAT and BCT effluent guidelines for many industries by the deadline. In the meantime, permit writers may attempt the time-consuming task of developing effluent limitations for each facility individually. However, even if this virtually impossible task could be completed before the deadline, industry would not have time to comply by the deadline. It often takes at least three years to design, purchase and install any required technology.

A more workable approach would eliminate the fixed dates in the act and instead require compliance 36 months from the dates BAT and BCT effluent guidelines are established.

In addition, in order to avoid "treatment for treatment's sake," the act's requirement for BAT limitations should be re-evaluated. For many industries, existing technology, known as Best Practicable Control Technology (BPT), is effectively removing toxic pollutants present in raw wastewaters. In these cases, more stringent industry-wide requirements for BAT should not be necessary. Further, the concentration of a pollutant which will produce a toxic effect in the receiving water varies from stream to stream and pollutant to pollutant. Therefore, the act should allow case-by-case modification of those BAT requirements which are more stringent than BPT.

For these reasons,

1. Instead of fixed dates for industrial compliance with Best Available Technology (BAT) and Best Conventional Technology (BCT), compliance should be required 36 months from the dates BAT and BCT effluent guidelines are established.

2. BAT should be designated as equivalent to Best Practicable Control Technology (BPT) for those industries where BPT adequately controls the discharge of toxic pollutants.

3. Modification of BAT requirements should be allowed in those limited cases where a discharger can demonstrate that the effluent from its facility does not violate water quality standards or adversely impact the receiving waters.

NPDES Permits. Under the Clean Water Act a facility must obtain a National Pollutant Discharge Elimination System (NPDES) permit before discharging pollutants into the nation's waters. The act makes it unlawful to discharge without a permit.

The act requires EPA and the states to renew permits too frequently and to issue permits for sources which are insignificant contributors to water pollution. The result is an unmanageable backlog of permits awaiting action.

Extending the lifetime of permits and exempting insignificant discharges will allow both industry and government to focus on the most serious problem areas affecting water quality.

Therefore,

1. The maximum lifetime of NPDES permits should be extended to 10 years.

2. EPA should be authorized to exempt environmentally insignificant discharges from the NPDES permit program. That is, EPA should be allowed (a) to exempt appropriate discharges, such as uncontaminated storm water runoff, from categories of point sources and (b) to exempt specific point source discharges on a case-by-case basis.

Permits for Discharging Dredged or Fill Materials. The Clean Water Act in Section 404 requires a permit for essentially all discharges of dredged or fill materials into the "waters of the United States." This program is unduly complex and has a conflicting management structure. Inordinate delays and unnecessary costs are the result, without commensurate environmental protection.

First, the act should be modified to reduce the geographic scope of the dredge or fill program. Before 1977, discharges of dredged or fill materials were regulated only in the nation's truly navigable waters. However, the program has been expanded by court interpretation to regulate other waters that are not truly navigable, including intermittent streams, normally dry river bottoms, sandflats and, in some cases, merely damp ground. As a result, time-consuming and costly

permits often must be obtained for activities in areas which have an insignificant effect -- or, in many cases, no effect -- on the goals of the Clean Water Act.

Second, administrative authority and responsibilities for the program should be placed with the Corps of Engineers. Dual control of the permit program between the Corps and the Environmental Protection Agency (EPA) creates uncertainty in the administrative process. The Corps of Engineers, which has extensive experience with discharges of dredged and fill materials, manages the program. However, both EPA and the Corps issue separate requirements for permits. The result is that the applicant must comply with two sets of complex, sometimes conflicting requirements. Moreover, EPA has the authority to veto a permit issued by the Corps.

Finally, the act should be modified to allow better balanced consideration of the nation's energy, mineral and other natural resource needs throughout the decision-making process.

For these reasons,

1. Substantially reduce the geographic scope of the Section 404 permit program.

2. Administrative authority over the Section 404 permit program should be centralized in one federal agency, the Corps of Engineers, providing EPA with a consultative role.

3. The permit process should be streamlined to ensure the timely granting or denial of a permit application.

4. The act should require that permit conditions and stipulations relate only to the permitted activity -- the discharge of dredged or fill material.

5. Reviewing agencies should be required to demonstrate to the Corps the need for requested permit stipulations.

6. The act should require that important national interests and values be balanced and considered throughout the decision-making process.

Ocean Discharge Criteria. Discharges into the ocean are regulated under the NPDES permit program. In addition, the act requires separate consideration of "ocean discharge criteria." These criteria duplicate both the NPDES permit program and other important environmental controls that already protect the ocean from unreasonable degradation.

For example, for oil and gas drilling on the Outer Continental Shelf (OCS), several steps are required. First,

before the federal government leases land on the OCS, the Department of the Interior prepares an Environmental Impact Statement, assessing the environmental effects of the proposed activity. Next, the company must obtain an NPDES permit which imposes technology-based treatment requirements on the discharge of pollutants. Before operations can begin, the company must prepare and have approved by the Department of the Interior a site-specific plan of exploration and an environmental report. Before production can begin, the company must prepare a production plan and another environmental report. And, for a new producing area, the Department of the Interior must prepare another Environmental Impact Statement.

The ocean discharge requirement is, in effect, an additional environmental study that duplicates these other assessments. As a result, the search for energy offshore can be delayed -- without adding appreciably to existing information or improving water quality. This additional and unnecessary environmental impact assessment should not be required.

For these reasons, the act should specify that:

1. Permit writers can assume that ocean discharges cause no unreasonable degradation of ocean waters if the discharges comply with NPDES permit effluent limitations and conditions.

2. A separate Ocean Discharge Criteria Evaluation is not required in an area for which an Environmental Impact Statement or similar analysis has been prepared by the Department of the Interior or a state before a lease sale in the area.

3. An NPDES permit should not be denied under Section 403 of the Clean Water Act unless EPA determines that the discharge would cause unreasonable degradation of the marine environment.

New Source Permits. Two aspects of the act's requirements for new facilities are inefficient and costly: the definition of a new source and the requirement for an Environmental Impact Statement (EIS) under the National Environmental Policy Act.

A facility is defined as a new source if its construction is begun after an applicable performance standard is proposed -- but before the standard is finalized. Although the act requires EPA to issue new source standards within 120 days of proposal, the agency has found this requirement impossible to meet. Thus, industry must design new plants to meet proposed effluent standards which EPA may later change. This situation makes the design and installation of a new facility an unreasonably risky undertaking.

The EIS requirement is intended to ensure that federal agencies adequately address environmental considerations. For

NPDES permits, this costly requirement is redundant because environmental concerns already play a paramount role in EPA's decisions. Moreover, permits for new sources issued under other environmental statutes are exempt from the EIS requirement.

For these reasons,

1. The definition of a new source should be based on the date an applicable new performance standard is promulgated, rather than on the date it is proposed.

2. NPDES permits for new facilities should be exempt from review under the National Environmental Policy Act and from its associated requirement for an Environmental Impact Statement.

Groundwater

Groundwater is one of our nation's most valuable natural resources because of its high quality, abundance, availability and relative cost. It accounts for almost half the U.S. drinking water supply and for over two-thirds of the water used for irrigation, primarily in the western states. It is also a significant water supply for industrial uses.²¹

Increased reliance on groundwater has been accompanied by increased concern over its continued availability and quality. Particular concern has focused on possible groundwater contamination from hazardous wastes. As a result, a number of laws and regulations at both the state and federal levels now protect groundwater quality.

On the federal level, groundwater is protected under the Safe Drinking Water Act; the Resource Conservation and Recovery Act (RCRA); the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), the Clean Water Act, the Toxic Substances Control Act and the Federal Insecticide, Fungicide and Rodenticide Act. These programs are administered largely by EPA which provides the framework for state regulations. In November 1980, EPA proposed a groundwater protection policy that would coordinate the various federal groundwater programs and would give the states a primary role in the groundwater protection effort. EPA is expected to implement the program in 1983.

State and local agencies are actively implementing groundwater protection measures. All 50 states have authority for implementing drinking water programs under the Safe Drinking Water Act. Ten states have the authority to implement underground injection control programs which regulate the injection of substances into underground water. Under RCRA, more than 38 states are administering their own hazardous waste programs

with the rest rapidly moving toward that goal. Most states are managing their own resources under the Clean Water Act, and 19 states have cooperative agreements with the federal government for implementing Superfund activities under CERCLA.²²

Historically, the states have had the primary responsibility for allocating their groundwater resources. They are best suited to manage groundwater resources and protection programs because the occurrence of groundwater and its value as a resource vary from state to state.

Acid Rain

Acid rain is a shorthand term for a complex phenomenon that begins when emissions of various carbon, nitrogen and sulfur compounds from both natural and man-related sources oxidize in the atmosphere. The reaction produces acidity in rain or snow which then falls on vegetation, soils, surface water and materials. Rain also traps windblown dust which may be strongly alkaline or acidic. Volcanic eruptions, wildfire, lightning, emissions from living organisms, and other natural phenomena release carbon, nitrogen or sulfur compounds into the atmosphere.

Human activity in industrial societies contributes to the already sizeable natural concentrations of organic acids and oxides of nitrogen and sulfur in the atmosphere. Coal-fired electric power plants and mineral smelters are important man-made sources of sulfur oxides. All forms of fossil fuel combustion, including those associated with automobiles, emit nitrogen and carbon oxides.

It is not easy to fully assess either the natural or man-made causes of acid precipitation in a given location. Some pollutants may remain in the air a relatively long period of time and can be transported considerable distances -- crossing geographical and political boundaries. Thus, efforts to develop state, regional or international control measures can be difficult.

Currently, there is scientific uncertainty about fundamental issues concerning acid precipitation. Precipitation in some areas is in fact acidic, but debate continues on whether acidity is increasing and on what the causes might be. Some lakes in some areas of North America and Europe are too acidic to support fish, and debate centers on whether this has been caused by a claimed increase in acid precipitation or by other factors.

Acid precipitation has not been shown to have an adverse effect on the health of humans. The EPA criteria document on sulfur oxides agrees that adverse health effects are not currently attributable to acidic precipitation.²³

Basically, there are two conflicting positions on what should be done about acid precipitation. They are:

1. Measures should be taken to reduce nitrogen oxides and sulfur oxides emissions and, thereby, reduce the potential for acid precipitation.

2. The relationship between sources and amounts of sulfur oxides and nitrogen oxides and acid precipitation is extremely complex and not well enough understood at the present time to permit an intelligent identification of major causes or of cost-effective remedies.

People who favor the first position believe that increased source controls are warranted by what is currently known about acid precipitation.

Those who favor the second position believe that specific environmental controls based on acid precipitation are premature. Proponents of this position agree that further research is needed before the need for any optimal type of controls can be determined.

The Clean Air Act does not specifically address the problem of acid rain. The act is structured primarily around a cause-and-effect supposition that air pollution can be related to a particular source or well-defined group of sources. In the case of acid precipitation, no clear relationship has yet been established with specific emissions. Therefore, further research is in the public interest.

Moreover, regulation to achieve any objective related to acid precipitation should be cost-effective -- a difficult task while much remains disputed or unknown about the sources, transport and effects of acid precipitation. Thus, cost-effective controls will also require further research.

Summing Up

In this decade of the '80s, public support for environmental programs remains strong. In 1980, the president's Council on Environmental Quality said:

Asking individuals to choose among rival alternatives is an especially revealing way to determine public preferences. Such tradeoffs often arise in discussions of environmental policy because controls may increase the cost of business and government activities, because maintenance of environmental quality is sometimes viewed as inconsistent with a rapidly growing economy, and because some of the proposed energy supply options involve environmental costs. In recent

years several polls included economic tradeoff questions in an effort to discover whether people believe that environmental protection is worth the costs. The results have consistently shown strong support for environmental programs.²⁴

Americans have also indicated that they do not want to choose between economic well-being and environmental protection. A major public opinion survey conducted by Research & Forecasts concluded:

Those who say the goals of economic development and environmental preservation are irreconcilable -- be they leaders in government, business, or the environmental movement -- are out of touch with public sentiment and out of touch with what is actually taking place in the nation's communities. Americans want both economic revitalization and [environmental] protection and, what's more, they believe they can have both.²⁵

Achieving the nation's environmental, economic and energy goals will require the cooperation of all participants in the environmental debate. However, more often than not, that debate has resulted in the polarization of opposing factions. Brock Evans, Vice President for National Issues, National Audubon Society, speaking at an environment and energy conference, commented on the need for cooperation:

The great events and forces now dominating and affecting our national life together -- the state of the economy, the rising unemployment, pressures of foreign competition, a tumult of social change -- all are far too important to let whatever may have been in the past between us blind us to the opportunities of the future.²⁶

As a nation, we can strive for harmony in achieving energy and environmental goals. Environmental protection need not mean energy stagnation. And energy development need not mean environmental degradation. We can have both environmental protection and energy development if our environmental laws allow.

The basic question is not whether environmental regulation is necessary, but how to regulate wisely. Wise regulation must include simplified permits, cost/benefit analysis, review of existing standards, flexible rules, innovative pollution control concepts and better coordination of federal, state and local regulation. These more realistic environmental regulations will allow both environmental progress and energy production -- the harmony we seek.

VIII. GOVERNMENT LANDS -- AN ENERGY RESOURCE

Improving the nation's energy security will depend not only on more efficient and balanced environmental regulations, but also on the careful use of areas with the greatest energy potential.

The United States occupies a fortunate position in a world that is hungry for energy. Nature placed vast resources within our borders and beneath our offshore waters.

Americans have used some of those resources to achieve a high standard of living. However, this country has not developed its full energy potential -- or, therefore, its full potential for more comfortable lives for all its citizens.

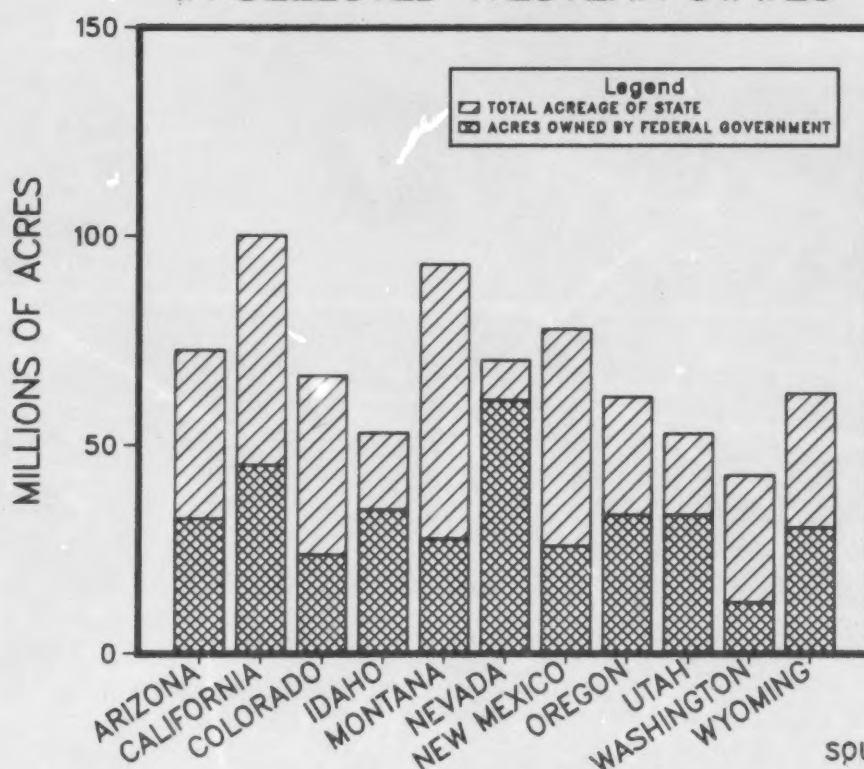
Many of the high-potential areas for producing oil, natural gas, coal, oil shale, tar sands, geothermal energy and other important minerals are believed to lie within the onshore and offshore areas controlled by the federal government. Hundreds of millions of those acres have never been made available for exploration. Millions of other acres have been restricted to petroleum operations to some degree.

What the Government Controls

The federal government -- as of September 30, 1980 -- owned 720 million acres onshore in the United States, including 307 million acres in Alaska.¹ (See graph, "Federal Land Ownership in Selected Western States.") On that date, the government also retained the subsurface mineral rights to an additional 66 million acres.² It is estimated that, at the beginning of 1982, the area owned by the federal government in Alaska had been reduced to about 300 million acres through transfers to the state of Alaska and to Alaskan natives.³ (See graph, "Federal Ownership of Alaska Lands.") These transfers were made under terms of the 1958 Alaska Statehood Act,⁴ as well as under the Alaska Native Claims Settlement Act of 1971⁵ and the Alaska National Interest Lands Conservation Act of 1980.⁶

As of December 31, 1982, 162 million onshore acres owned by the U.S. government were under lease for oil and gas operations. That represented about 23 percent of all onshore federal lands.⁷

FEDERAL LAND OWNERSHIP IN SELECTED WESTERN STATES



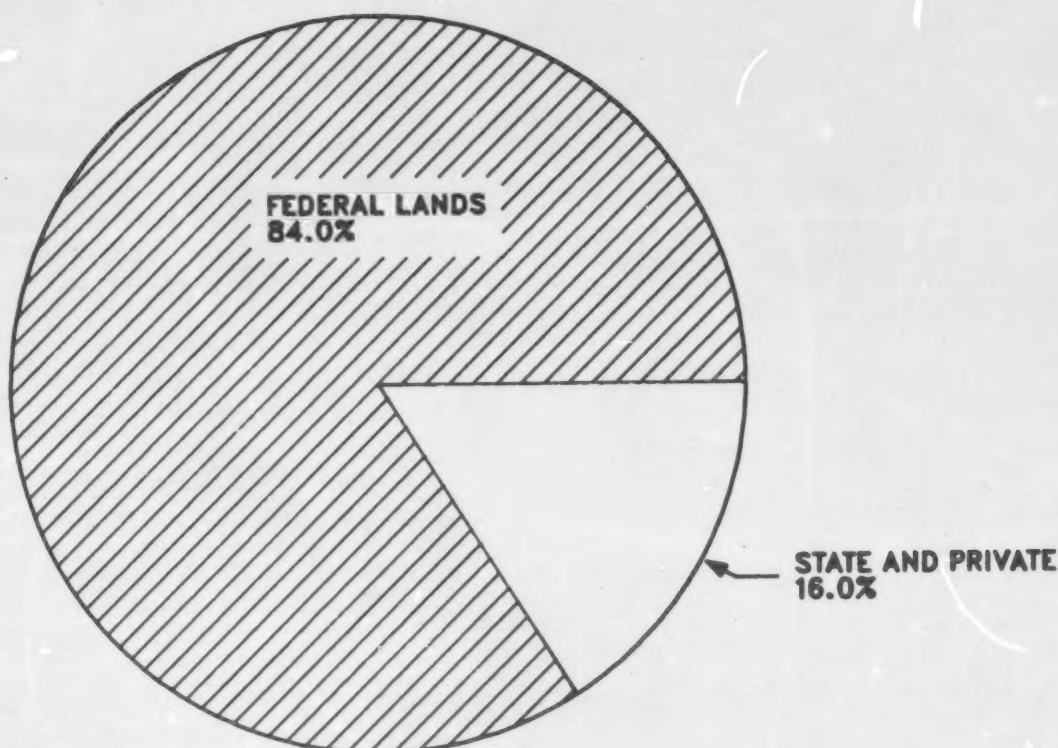
SOURCE: SEE APPENDIX

Offshore, the government controls nearly a billion acres. Some 528 million acres of that total are submerged lands on the nation's Outer Continental Shelf (OCS) out to a water depth of 200 meters. The remaining 438 million acres are in deeper waters of the continental slope out to a depth of 2,500 meters.⁸

From the beginning of the federal offshore leasing program in 1954 through April 26, 1983, the government had sold leases on some 24 million OCS acres -- about 2 percent of the total federal offshore area.⁹ As of December 31, 1982, leases were still in effect on some 13 million acres.¹⁰

Not all areas of the OCS, of course, are believed to hold the potential for oil and gas resources. Nevertheless, many areas -- particularly some offshore sedimentary basins -- that do have such potential have not been leased to date.

FEDERAL OWNERSHIP OF ALASKA LANDS



SOURCE: SEE APPENDIX

Some other nations have moved ahead much faster in permitting oil and natural gas exploration in their offshore waters. For example, in one sale in 1971, the United Kingdom (UK) leased more OCS acreage (15.1 million acres) than the United States leased in the 24-year period from 1954 through 1977.¹¹ The UK's offshore area is small compared with that of the United States. Yet, since early 1964, the British government has offered more than 180 million offshore acres for leasing and has leased 64.6 million acres of those lands. That is more than two and one-half times as much offshore acreage as had been leased by the U.S. government through May 1983.¹²

Federal lands, onshore and offshore, have been estimated to contain the following energy resources:

- 85 percent of our crude oil;
- 40 percent of the natural gas;
- 40 percent of the uranium;
- 35 percent of U.S. coal resources;
- 80 percent of our oil shale;
- 85 percent of the nation's tar sands resources; and
- 50 percent of our geothermal resources.¹³

The U.S. Geological Survey (USGS) estimates that as much as 95 percent of our nation's offshore oil and gas are under lands owned by the federal government. Onshore, the study indicates government lands -- excluding Alaska -- contain 30 percent of our crude oil and 25 percent of our natural gas.¹⁴ Some oil companies believe that as much as 70 percent of the remaining oil and gas to be found in the United States may lie beneath government lands onshore and offshore.¹⁵

Out of the approximately 411 million acres of onshore lands in the lower 48 states owned by the federal government in 1980, nearly 261 million acres were identified by the U.S. Geological Survey and the General Services Administration as "prospectively valuable oil and gas lands," that is, "areas of federal lands where geologic conditions offer some possibility for the occurrence of oil and gas, even if the presence of hydrocarbons has not been established."¹⁶

In addition, the Interior Department states that more than 95 million acres of government lands have been identified as potentially valuable for the production of geothermal energy.¹⁷

Geologists also believe significant amounts of non-fuel minerals and metals could be found within the onshore government lands. This is important because the United States is dependent on foreign sources for many minerals and metals used in this country.

Thus, efficient use of the lands controlled by the government can do much to move this country toward greater self-sufficiency in energy and other essential materials.

Government Acquisition of Land

The federal government has always been the largest single landowner in the United States. At various times it has held title to about four-fifths of the nation's total land area.

The government acquired those lands in a variety of ways. Some of the original 13 states ceded to the central government vast unsettled areas lying west of the Appalachian Mountains. The United States bought the Louisiana Territory from France, Florida from Spain and Alaska from Russia. Some lands were purchased from the independent nation of Texas and from Mexico. Other lands -- in the Pacific Northwest -- were added through a treaty with Great Britain.

Over the years, more than a billion acres of federal lands were transferred into state or private ownership to encourage homesteading, agriculture, construction of schools and railroads, support of higher education and for other purposes.¹⁸

Of the nearly one-third of the nation's acreage still in government hands, some lands are reserved for national parks, wildlife refuges, military bases and other special purposes. But hundreds of millions of those acres have never been dedicated to such specific uses and have not been made available for exploration for oil, gas or other energy sources.

Access and Environment Are Compatible

Increased exploration of those government lands can be accomplished compatibly with environmental protection.

Five years ago, an Interior Department task force reported that "in the entire history of the United States the total land area disturbed by all mining, including coal, stone, oil, gas, sand and gravel, and metal and nonmetallic ores, has been less than 0.3 percent of the total surface area of this country."¹⁹

Petroleum operations, for example, are compatible with environmental considerations. Operations are often temporary in nature and disturb relatively small areas of land. Seismic surveys and test drilling involve minimal surface disturbance of the land over a fairly short period.

An oil well site rarely covers more than a few acres. Several wells usually can provide enough information to assess the potential of a large area.

If a well proves to be a dry hole, the rig is removed and the well site is restored. If a commercial discovery is made, the normal productive life of a field is 25 to 30 years. Production facilities involve only small-scale disturbances that

can be substantially or entirely corrected after production ceases.

Furthermore, state and federal agencies carefully monitor every phase of petroleum operations to assure that all applicable environmental regulations are obeyed.

Experience in many areas has proved that petroleum operations are compatible with many other land uses, including wildlife management. This has been demonstrated from the Kenai Moose Range and the caribou grazing grounds in Alaska to the wildlife refuges along the coast of the Gulf of Mexico.

On the North Slope of Alaska, wildlife have adapted easily to the presence of men and their equipment. Caribou, moose and their calves can be seen grazing within a few hundred yards of drilling rigs, or resting and browsing beneath the elevated portions of the trans Alaska pipeline, because it is warmer there and the grass is literally greener.

The Wildlife Refuge Management Act specifically states that oil and gas operations may proceed on wildlife refuges. For several years, however, federal administrators have refused to accept applications for leases in those areas, thus effectively withdrawing them from such use.

When carried on in an environmentally responsible manner, petroleum exploration and production need not harm animal habitats nor threaten other desirable values. Zero environmental impact is not possible, of course; even a solitary camper will in some way affect the environment. But limited temporary effects from careful exploration may, in some instances, be a bargain price to pay for producing energy that cannot be obtained in any other way.

A Source of Revenue for the Government

It is sometimes overlooked that petroleum development can also be an important source of revenue for the government.

Preliminary data from the Interior Department indicate that, through 1982, the total cumulative value of oil, gas and related products from federal OCS operations is estimated at nearly \$104 billion. In the same years, the oil companies paid more than \$58 billion to the federal government in offshore lease bonuses, rentals and royalties.²⁰ Thus, even before taxes, the government received about 57 percent of the value of oil and gas production from federal leases on the Outer Continental Shelf.

During 1982 alone, oil companies paid nearly \$4 billion in cash bonuses for the right to explore leases in federal off-

shore waters. The record high annual bonus payment was set in 1981, when \$6.6 billion was paid for offshore federal oil and gas leases.²¹

Royalty payments from offshore oil and gas production in 1982 amounted to \$3.8 billion. Such payments provided over 79 percent of the \$4.8 billion the federal government collected in 1982 for its onshore and offshore production of oil, natural gas, coal, potash, phosphate, sodium and other minerals.²²

Revenues to the federal government from onshore oil and gas leases have been substantial, also. For the period 1920 through 1982, the government has received some \$6.5 billion from onshore lease royalties and hundreds of millions of dollars more have been received from bonus payments and rental fees.²³

Facts Needed to Plan for the Future

The companies that explore for oil and natural gas believe they can find and produce a great deal more energy. Some analysts have estimated the future output of oil and natural gas in the United States at 40 times current annual production levels. Some estimates are higher, while others are lower. One reason for these honest differences of opinion is that even the "experts" do not have all the facts. Reliable information on oil and gas resources can be provided only by exploration and drilling.

It would be in the nation's best interest to find out what energy resources lie beneath the government lands before decisions are reached about the future status of those lands.

If large new supplies can be found, all Americans will share the benefits of more secure energy resources, more stable energy prices, a sounder economy and a more solid foreign policy. If, on the other hand, discoveries fall below expectations, the people of this country will know that they must move more quickly to develop alternative energy sources.

Several years may be required to find and develop new oil and gas reserves in frontier areas such as Alaska, the Rocky Mountains and the Outer Continental Shelf. Therefore, it is essential that unnecessary delays be eliminated as promptly as feasible.

Restrictions Slow Energy Development

Many of the laws governing the use of government lands specify that Congress intended the natural resources on those lands to be developed in an orderly and timely manner to meet the needs of all Americans.

The laws also state that multiple use of government lands should be practiced wherever practical. This means that the lands should be managed in ways that allow more than one compatible activity to take place in a given area, either simultaneously or in sequence.

These principles are clearly stated in many of the laws affecting resource development on government lands, including such laws as the Mining Law of 1872, the Mineral Leasing Act of 1920 and the Federal Land Policy Management Act of 1976.²⁴ Nevertheless, in many instances, the intent of Congress has not been carried out. Severe restraints have been placed on resource development activities on government lands, particularly during the past 15 years.

These restraints built up gradually over a period of years and in various ways. Some government agencies adopted regulations more restrictive than the laws called for. In some instances, officials either refused to accept applications for leases on certain government lands that were technically open to exploration, or they accepted the applications and kept them on file for up to 10 years without taking action.²⁵

Some of the problems and delays were caused by the passage of laws designed to protect the environment or for other purposes -- for example, the Clean Air Act and the Endangered Species Act. Although not intended as land-control measures, those laws had the effect of limiting energy production on both government and private lands. Other problems were caused by the lack of coordination among the various agencies involved.

Most Americans support laws and regulations that protect such unique areas as the Grand Canyon and Yellowstone National Park against commercial encroachment. But hundreds of millions of acres of government lands without special scenic value are either closed to energy development or are hemmed in by restrictions that effectively ban energy-related operations. These areas include some of the geological formations where scientists believe the nation has the best chance of finding major new oil and natural gas reserves.

Many of these restrictions were imposed without the American people or even government policy-makers being fully aware of all the facts. Areas were set aside with no assessment of their potential for the production of energy or other vital minerals. For years, no agency of the federal government kept a record of the cumulative impact of such actions on resource development.

The Extent of Withdrawals

It is difficult to estimate the amount of government land that has been formally withdrawn from oil and gas operations

because no one knows how much of this land is officially open to leasing.²⁶ Moreover, administrative withdrawals are not usually identified in agency land status records and, thus, have proven to be the most elusive closures of government lands. Such administrative withdrawals from mineral leasing can take place at any level within an agency. They are considered to be permanent and binding closures of the land.²⁷

It has been seven years since the studies by the Interior Department and the congressional Office of Technology Assessment addressed the question of how much federally-owned land was available for mineral exploration and production. Although the two agencies used somewhat different approaches, each concluded that at least two-thirds of the federal lands ranged from moderately restricted to completely withdrawn from minerals and energy development.²⁸

For example, the Interior Department (using 1974 data) found that 312.5 million acres were formally withdrawn and another 183 million acres were under such severe restrictions as to be effectively withdrawn. The two numbers add up to 495.5 million acres -- an area nearly five times as large as California. Moreover, neither study included data on areas that were closed to development by administrative decisions.

Substantial areas -- both in Alaska and the contiguous 48 states -- have been placed off limits to oil and gas operations since those studies were made. For example:

- The National Wilderness Preservation System -- which started out in 1964 as a modest withdrawal of some 9 million acres -- as of May 1, 1983, had grown to nearly 80 million acres. If all of the lands recommended for wilderness designation or being considered as wilderness study areas were to be included in the system, the program could grow to some 200 million acres. That's an area greater than the states of Georgia, Mississippi, Virginia, West Virginia, North Carolina, South Carolina and Florida combined.

The Wilderness Act of 1964 provides that, as of December 31, 1983, all lands that have been classified as wilderness will be closed to the development of oil, natural gas and other minerals.²⁹ Thus, the mineral resources underlying these lands may never be identified for future use.

- Under the Federal Land Policy and Management Act of 1976, the Bureau of Land Management must identify -- and, if warranted, designate and manage -- Areas of Critical Environmental Concern (ACECs) so as to protect and prevent irreparable damage to important historic, cultural, scenic or natural values. As of April 30, 1983, there were 108 ACECs covering some 845,000 acres. However, the Bureau of Land Management has

indicated that as many as 275 million acres of government lands could be eligible for ACEC designation.³⁰ These areas could be closed to mineral operations if environmental values are given priority over other uses.

GAO Urges More Use of Federal Lands

The General Accounting Office (GAO) published a study on February 11, 1981, urging that more government land be made available for oil and gas development and that leasing and permitting procedures be speeded up.³¹ The GAO said the United States faces "continuing prospects of large gaps between consumption of oil and gas and domestic production from conventional sources" unless corrective actions are taken.³²

The GAO study pointed out that exploration and production are being hampered by a number of factors. These include the withdrawal of areas from leasing; the imposition of burdensome stipulations on leases; long delays in the approval of leases and issuance of permits; and the failure to put expired leases back on the market. The study said some lands are withdrawn by law, some by executive order or public land orders, and some by "no leasing" policies established informally by officials of various federal agencies.³³ Moreover, GAO noted that some government agencies lack the funds and personnel to manage their lands efficiently.

"The effects of withdrawals of federal lands from oil and gas exploration are very large," the GAO said. "Closing lands or keeping already withdrawn lands closed without adequate justification or without determination and consideration of their oil and gas resources is not consistent with approaches needed to deal with energy problems."³⁴

The GAO noted that legislation will be required to correct some of the problems affecting oil and gas operations on federal lands. However, the study said administrators in various federal agencies can speed up leasing and drilling without waiting for significant changes in the basic resource and environmental laws.³⁵

Another GAO report, issued later in February 1981, said some federal agencies are delaying offshore drilling by not acting promptly on requests for permits and approvals of operational plans.³⁶ GAO recommended legislation to require agency action on such matters within 90 days of application. The report commented that the petroleum industry's record in searching for oil and gas after obtaining leases and permits was "credible," with most delays due to regulation or shortages of equipment.

Alaska -- Great Expectations, Little Development

America's northernmost state is an excellent example of an area where relatively little drilling has been done in spite of estimates that it has great oil and gas potential.

Alaska contains 365 million acres of land. That is nearly one-sixth of all the land in the United States and more than twice the total acreage in Texas. The U.S. Geological Survey estimates that onshore Alaska has more than 161 million acres of sedimentary rock -- the kind of formation in which virtually all oil and gas discoveries have been made.³⁷ But, except for the Prudhoe Bay, Kenai Peninsula and Cook Inlet areas, most of Alaska's potentially productive lands have been tested only sparingly or not at all.

A study published in February 1982 by the USGS estimated that onshore Alaska may contain as much as 14.6 billion barrels of undiscovered crude oil and as much as 62.3 trillion cubic feet of undiscovered natural gas (the energy equivalent of 11 billion barrels of oil).³⁸ Some geologists think that, with careful exploration of Alaska, those figures could be much higher.

During the years 1969 through 1980, thousands of applications were filed requesting exploration and drilling permits on government lands in Alaska. But the federal government, which owns nearly all of the land in that state, granted none of them.

Despite the fact that little is known about the real petroleum potential of Alaska, Congress enacted a law in November 1980 that may place major obstacles in the path of energy development in that state. The Alaska National Interest Lands Conservation Act placed 104 million acres of government land in conservation and recreation categories such as national parks, wildlife refuges and preserves, wilderness areas, forest lands, wild and scenic rivers and national monuments. The total area affected by that law is larger than the combined acreage in the states of Pennsylvania, Ohio, Indiana and Kentucky. Thus, oil and gas activities are flatly prohibited in much of onshore Alaska. Petroleum operations may be severely restricted in other areas covered by the new law, unless the act is amended or certain policies are revised to encourage energy development.

It should be noted that there has been significant movement towards opening more Alaskan lands to development in the past two years. In April 1981, the Department of the Interior asked industry and the public to identify areas of interest among more than 100 million acres of land under consideration for oil and gas leasing there. (Lands under consideration included all federal government lands except those in the National Petroleum Reserve-Alaska [NPR-A] and government lands closed by statute

to oil and gas leasing.)³⁹ As a result, in January 1982, the Department of the Interior identified more than 30 million acres to be included in a non-competitive leasing program. That program became effective in February 1982, with other areas to be opened later.⁴⁰

In early 1982, the Bureau of Land Management accepted high bids totaling more than \$57 million on some 653,000 acres in the NPR-A for oil and gas leases there.⁴¹ A second NPR-A offering in 1982 resulted in the acceptance of bids totaling \$9.7 million for some 252,000 acres. A third lease offering is scheduled for July 1983.⁴²

Delays Slow Offshore Exploration

Since drilling began in U.S. waters in the 1950s, the search has been subjected to many delays. Federal leasing has been a stop-and-go affair. Many areas believed to have great potential have not been offered for leasing. The program has been plagued by cancellations and postponements of scheduled sales. Many of the delays were caused by lawsuits that eventually were thrown out of court. Such delays have cost American consumers valuable time and money and increased this country's dependence on imported oil.

Here are some examples of delays:

- In August 1976, companies paid the government \$1.1 billion in bonuses for leases in the Baltimore Canyon area off the mid-Atlantic coast. Because of court challenges, the successful bidders had to wait 18 months before they could start drilling. Two sales were held in the area -- in 1979 and 1981 -- resulting in an additional \$363 million in bonuses paid to the government. In April 1983, another lease offering was made covering some 23 million acres. The sale was challenged by the states of New York, Maryland and Virginia; however, only four tracts bid on were within the area the states wanted to exclude from the sale on environmental grounds. Companies bid on some 228,000 acres, with high bids totaling \$71 million.⁴³

- A lawsuit forced cancellation of a January 1978 lease sale covering portions of the Georges Bank area, off New England. The sale was rescheduled for December 1979. At that time the companies paid the government \$816.5 million in cash bonuses. Government permitting and license approval bottlenecks caused further delay and drilling did not begin in the Georges Bank area until July 1981. As of January 1, 1983, drilling was completed on eight dry holes and no other drilling operations were underway.⁴⁴ It is estimated that exploration costs -- including the money paid to the government in lease bonuses -- had exceeded \$1.1 billion by September 30, 1982.⁴⁵

Even after leases are purchased and all permits obtained, offshore drilling often produces disappointing results. Here are some examples:

- In 1973, oil companies paid the government nearly \$1.5 billion in cash bonuses for leases in the eastern Gulf of Mexico, where the petroleum potential was thought to be high. Eighteen holes were drilled there at a cost of several million dollars without finding producible oil and gas.

- In 1976, the companies paid the government nearly \$560 million for leases in the northern Gulf of Alaska. The 11 wells drilled in that area to date were dry holes.

- In 1978, the government collected nearly \$101 million for leases in the Southeast Georgia Embayment, off the South Atlantic coast.⁴⁶ So far, the companies have drilled six dry holes there at a total estimated cost of \$23 million. A second lease offering was held in the area in August 1981. Companies paid the government nearly \$343 million for leases acquired in that sale.

- As of January 1, 1983, 27 wells had been drilled in the Baltimore Canyon area. Of these, 22 were dry holes and 5 resulted in potential discoveries. The estimated total cost thus far of these 27 wells has exceeded \$1.9 billion.⁴⁷ More drilling will be required to determine if the potential discoveries warrant commercial development.

Congress passed new legislation affecting OCS leasing and drilling late in 1978.⁴⁸ The law required the preparation of some 40 new or revised sets of regulations. Under the new law, operating offshore is now even more complex and time-consuming than before.

Draft proposals to speed up and expand the five-year OCS leasing schedule were announced in April 1981 by Interior Secretary James Watt and Energy Secretary James Edwards.⁴⁹ They said the changes, if adopted, will make more offshore acreage available for leasing, will cut substantially the time now required to start leasing in promising frontier areas and will use the market to select areas for leasing and exploration.

The most recent five-year schedule, issued in July 1982, calls for 41 lease sales in the years 1982-1987. Of these, 16 are scheduled for offshore Alaska, 12 for the Gulf of Mexico, 4 off California and 8 off the Atlantic coast. One sale reoffers tracts previously offered but not leased.⁵⁰ The new Department of the Interior lease schedule was prepared as part of an annual review of the leasing program required by law.

In 1982 federal offshore leases accounted for about 10 percent of the crude oil and condensate and about 25 percent of the marketed natural gas produced in the United States.⁵¹ These volumes of oil and gas were produced from the 2 percent of the federal OCS currently under lease for petroleum exploration. Oilmen are confident that more timely leasing of these offshore lands and simpler regulatory procedures can sharply increase the discovery of new reserves of oil and gas.

Onshore Government Leasing

Delays have also hindered energy development on government lands onshore. For example, the U.S. Forest Service announced in February 1981 that it was beginning to process about 500 applications for oil and gas leases on more than a million acres of national forest lands in northwestern Montana. Some of those applications had been filed a decade earlier.⁵²

Under the Mineral Leasing Act of 1920 and the Acquired Lands Act of 1947, substantial government onshore acreage was to be made available to oil and gas leasing.⁵³ The fact is, however, problems in acquiring access to government onshore lands and the anticipated administrative delays discouraged many oil companies from applying for leases.

It was far easier when potentially productive areas were available elsewhere for companies to acquire leases on private lands. And this was done. However, as America's petroleum energy needs grew, it became increasingly important to have access to both government and private lands. This has become particularly true in the western United States, where the government owns or manages the mineral rights to large land areas.

For example, according to figures available from the General Services Administration, the federal government, as of September 30, 1980, owned 84 percent of Alaskan lands, almost 87 percent of Nevada, more than 60 percent of Idaho and Utah, 54 percent of Oregon and more than 40 percent of Arizona, California and Wyoming.⁵⁴ Moreover, a recent General Accounting Office report indicates that, in four western states studied (Colorado, Nevada, New Mexico and Wyoming), of the more than 14 million acres of government lands formally withdrawn from exploration and production activity, nearly 55 percent had oil and gas potential.⁵⁵ The report also found that, of the more than 16.5 million acres restricted for wilderness consideration in those states, more than one-half had petroleum potential.⁵⁶

In 1982 the wells on those leases provided more than 5 percent of the liquid petroleum and nearly 7 percent of the marketed natural gas produced in this country.⁵⁷ Oilmen

believe those percentages can be increased significantly within the coming decade through improved access to government lands.

Access to Non-Petroleum Energy Resources

As noted in the chapters on coal and synthetic fuels, the problem of access to government lands is not limited to oil and gas exploration, development and production. With so much of the nation's energy resources underlying government lands, access is a major problem for the nation's emerging energy sources -- oil shale, tar sands, geothermal energy and synthetic fuels made from coal.

Delays in leasing and restrictions to access have had their effect on the development of these important non-petroleum energy sources. If these essential energy resources are to be developed in a timely and economical manner, changes must be made that minimize restrictions on their development.

The Department of the Interior has issued new leasing programs for the development of tar sands and geothermal resources on federal lands. A permanent oil shale program is currently under review with a lease sale scheduled to be held in 1984.

A major stumbling block to synthetic fuels development has been the Mineral Leasing Act of 1920, as amended by the Federal Coal Leasing Act Amendments of 1976 (FCLAA).⁵⁸ That legislation requires that federal coal leases reach commercial quantity production within 10 years or the lease will terminate. The FCLAA also prohibits leasing onshore oil and gas, coal, tar sands and several other minerals to a company which holds and has held a federal coal lease for 10 years without reaching commercial production.

Changes in these laws could help achieve effective development of federal coal and oil shale leasing. For example, oil shale leases larger than the 5,120 acres now permitted would encourage investment in the costly facilities needed to produce, refine and upgrade shale oil into usable products. Other needed changes include removing the one-lease-per-company limitation on oil shale leasing; clarifying the Department of the Interior's ability to issue leases covering more than one mineral; and allowing off-site surface leasing in oil shale areas for locating processing and waste disposal facilities.

* * * * *

The United States can continue to move toward increased energy security by developing and using our domestic energy resources. However, increased access to these resources is essential.

IX. ECONOMIC BENEFITS OF REDUCING IMPORTS

Additional domestic energy production and continued progress in conservation resulting from market adjustments have enabled the United States to cut oil imports significantly in the last several years. This reduction in oil imports has put downward pressure on world oil prices set by OPEC. We now face a smaller risk of sudden, steep increases in world oil prices and probably would be less affected economically by a supply interruption. By providing a more stable environment for business decisions, we enjoy a more favorable outlook for economic growth.

Additional domestic energy, produced efficiently, and continued conservation should:

- further weaken OPEC's ability to raise world oil prices;
- make us less vulnerable to a sudden reduction in oil imports; and
- reduce payments for foreign oil and increase U.S. output of goods and services.

Weakened OPEC Ability to Raise World Oil Prices

OPEC's pricing power is based on demand for its product. More energy produced and conserved in the United States has been and can continue to be effective in restraining OPEC from raising prices.

Throughout the 1970s, demand for foreign oil increased steadily in the United States -- with imports totaling more than 8 million barrels a day by the end of 1979. However, by 1981, the United States -- and its allies -- were taking decisive steps to curb OPEC's power by conserving and producing more energy.

In the United States, higher oil prices and the removal of price controls on oil brought striking results. As a result of higher prices, drilling for oil -- which by 1973 had dropped by nearly three-fourths from the peak levels of the 1950s -- rose sharply in the late 1970s, set new records in 1980 and was up

even more in 1981. In 1982, drilling activity declined from the levels reached in 1981. However, the level of activity was still substantially greater than the low point of the early 1970s and the number of wells actually completed reached an all-time record.

These greater efforts to find and produce oil have had encouraging results. After a decade of decline, oil production has been stable so far in the 1980s.

At the same time, the nation has made dramatic progress in oil conservation. After growing steadily for 28 of the previous 30 years, oil use was down 2 percent in 1979, 8 percent in 1980, 6 percent in 1981, and an additional 5 percent in 1982. It continued to decline into 1983; for the first five months of the year, total oil consumption in 1983 was 4 percent less than in 1982.

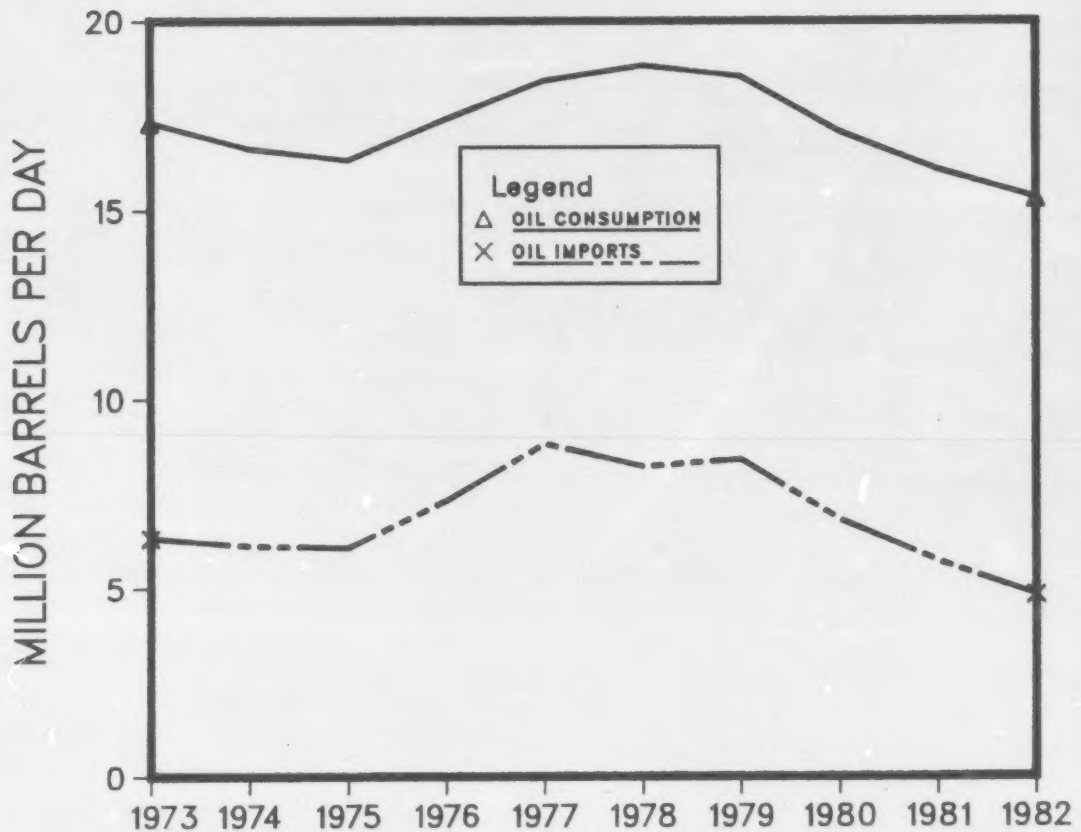
This remarkable progress in energy conservation and production has reduced U.S. demand for foreign oil. After roughly doubling in each of the last three decades, in 1982 imports were down more than 40 percent since 1979. (See graph, "U.S. Dependence on Imported Oil.") Likewise, additional energy production and conservation in other non-OPEC countries has further reduced worldwide demand for oil imports.

The balance in free world oil production has been changing. Through the mid-1970s, OPEC was producing about 65 percent of the free world's total. Since then -- with falling OPEC production and rising production elsewhere in the free world -- the scales have moved. By 1982, non-OPEC countries were out-producing OPEC. By the first two months of 1983, non-OPEC nations were producing over 60 percent, and OPEC under 40 percent, of the free world's oil. (See graph, "Crude Oil Production.")

These developments in the United States and other non-OPEC countries have reduced sales for OPEC members. Since 1979, when OPEC was producing nearly 31 million barrels a day of oil, total production has dropped dramatically, primarily because its members were unable to sell greater amounts of oil at the prices they requested. By early 1983, production had dropped to half the 1979 level.

In early 1982, faced with reduced demand and falling prices, members of OPEC formally agreed to coordinate production for the first time in the cartel's 22-year history. They set an overall production limit of 18 million barrels a day -- with Saudi Arabia cutting its production an additional half million barrels a day. And they agreed to try to hold the reference price for crude oil at \$34 a barrel.

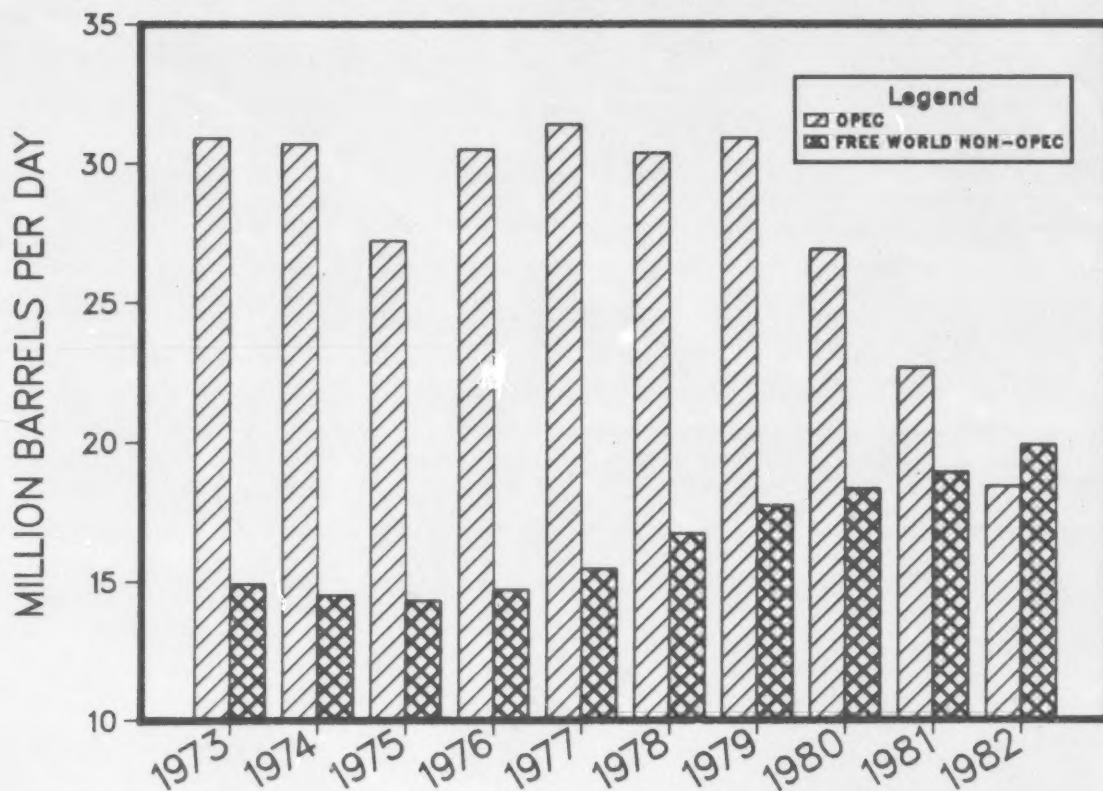
U.S. DEPENDENCE ON IMPORTED OIL



SOURCE: SEE APPENDIX

But OPEC discovered in 1982 that worldwide demand for its oil was too weak for its members to produce and sell 18 million barrels of oil a day at \$34 a barrel. Conservation, the worldwide recession and greater oil production by non-OPEC nations prevented OPEC from achieving its objectives. Actual selling prices dipped below \$34 a barrel; and by early 1983 OPEC's production was about 14 million barrels a day, well below the "limit" of 18 million barrels a day. Because market conditions defied the benchmark price of \$34 a barrel, OPEC members agreed in March 1983 to a benchmark price of \$29 a barrel, which was closer to actual selling prices on world oil markets.

CRUDE OIL PRODUCTION OPEC VERSUS FREE WORLD NON-OPEC



SOURCE: SEE APPENDIX

The future trend in world prices depends, in part, on choices to be made by other countries, including the United States. This nation, with its vast energy resources, and other non-OPEC countries can continue to make a dramatic contribution to the changing balance in world oil production by producing more energy, continuing to conserve and, thereby, reducing the market for OPEC oil still further.

Petroleum prices tend to be sensitive to changes in supply. That is, a relatively small change in the amount of oil supplied can cause a much larger percentage change in price. This means that increased U.S. energy production and conservation can make a difference in our favor -- just as our

high level of dependence on foreign oil in the past made a difference in OPEC's favor.

In the 1970s, world oil markets underwent two major price shocks triggered by relatively small supply reductions: the 1973-1974 embargo and then, later, the Iranian revolution. At the time of both crises, we depended heavily on OPEC for fuel to supply factories, heat homes, run automobiles and operate other machinery. In this environment, world oil prices increased substantially with only small disruptions in oil supplies.

More recently, however, increased supplies and conservation in the United States and other countries outside OPEC have caused the reverse effect. A so-called "glut" -- amounting to just a small percent of total free world supplies -- forced foreign oil producers to cut both price and production substantially. The United States and other countries can help this trend continue for as long as possible by freeing up energy markets.

Recent events prove that the United States need not simply accept OPEC's decision on the cost or availability of energy. Our extensive energy resources can add substantially to supply -- if government policies permit their development and allow energy markets to operate.

Lessened Vulnerability to a Sudden Reduction in Oil Imports

In the past several years, the nation has reduced imports significantly -- to about pre-embargo levels of the early 1970s.

However, it would be dangerous for recent progress to allow us to believe that we are not vulnerable to another disruption.

Commenting on that danger, Professor M. A. Adelman of the Massachusetts Institute of Technology, stated in his 1982 presidential address before the International Association of Energy Economists:

I expect the export decline [of OPEC oil] to continue, as oil consumption stagnates or declines and non-OPEC production creeps up. Yet, this tendency to lower OPEC exports was well under way in 1979, and it did not spare us a worse convulsion than in 1973. There is no prospect that supply out of the unstable areas will cease to be of great importance to the consuming countries, and therefore no prospect of eliminating insecurity.¹

Even at our current level of dependence on foreign oil, a sudden reduction in imports would exact a heavy price in terms

of lost jobs and income. The embargo and the sudden jump in world oil prices in 1973-1974 provide important evidence of this vulnerability. The Federal Energy Administration, now the Department of Energy, estimated that the 1973-1974 embargo cost Americans \$10 billion to \$20 billion in lost income.² Robert Rasche and John Tatom, writing in the monthly Review of the Federal Reserve Bank of St. Louis, estimated that the increase in world oil prices imposed by OPEC in 1973-1974 reduced domestic potential output by approximately 5 percent between the fourth quarters of 1973 and 1974.³ This loss of production potential was equal to an estimated \$60 billion (in 1972 dollars).

In 1979, the United States imported almost three times as much oil from the members of OPEC as in 1972, the year before the embargo. Then, events in Iran, which reduced supplies from that country, precipitated sharp increases in world oil prices.

Professor Adelman, commenting on the likelihood of another foreign oil supply disruption, said:

There are many sources of disruption. Although the probability of any one type in any one year is low, the chances of escaping them all for several years are also low.⁴

More domestic energy, efficiently produced, helps guard against the danger of supply disruption in two ways: First, by making it more difficult for OPEC to suddenly and sharply raise prices; second, by increasing our energy self-sufficiency. Through conservation and the production of additional domestic energy -- through efficient development and use of our own resources -- the United States will be better able to handle a sudden disruption in world oil supplies. Fewer jobs would be in jeopardy. Less real income and output would be lost. This is the kind of relative security Americans enjoyed in the '50s and '60s.

Reduced Foreign Oil Payments -- Increased Goods and Services

The United States can choose to produce substantially more energy using fewer resources than OPEC has been asking for its oil. If the United States can obtain energy more cheaply, then Americans can produce more of the other products and services they need.

Because of past price increases by OPEC and because of price increases brought about by unforeseen reductions in world oil supplies, our bill for imported oil grew from \$26 billion in 1974, the year the embargo ended, to \$60 billion in 1979. Our payments for foreign oil in 1980 approached \$80 billion.

In 1981 and 1982, increased conservation and production of energy has helped the nation reduce imports -- and helped to erode OPEC's ability to continue to raise prices. U.S. oil imports in both 1981 and 1982 were lower than in any year since 1973. That progress, along with lower world oil prices, was reflected in a reduced import bill of \$76.7 billion in 1981 and \$60.5 billion in 1982.

But the bill is still higher than need be. These figures represent the amount of time and resources that Americans must spend making the products and services necessary to pay foreign oil producers. As Richard Whalen stated in the March 1980 issue of Harper's magazine, "Whether at home or overseas, a dollar, after all, is a claim, an IOU against the U.S. government."⁵ OPEC agrees to accept our dollars in exchange for their oil because we have promised that, in return, OPEC can spend each and every dollar for the things we make. These products and services, provided by Americans to foreign producers, are the true cost of foreign oil.

However, this nation can choose to send fewer dollars abroad because we can provide additional domestic energy with less labor, capital and other resources than it has taken to buy foreign oil.

With efficient domestic production and conservation reducing oil imports, more of our resources are saved to help provide more housing, education, health care, clothing, food, etc., and to satisfy other important consumer needs. Additional supplies of these products and services contribute to lower rates of inflation.

Conclusion

We have made great progress in meeting the challenge of increased energy and economic security. But the challenge now is to maintain that progress by continuing to allow energy markets to operate. Otherwise, imports might once again climb to levels greater than need be, giving OPEC more leverage to increase prices. Moreover, the danger of a possible disruption in foreign oil supplies has not disappeared.

The nation's extensive energy resources, if we choose to develop them efficiently, can help meet this continuing challenge. By exercising that choice, Americans can further restore their energy and economic security. Not only would the outlook for economic growth and less inflation be more favorable, but Americans would have more control over decisions and events that affect their well-being.

X. ENERGY SECURITY -- INDIVIDUAL BENEFITS

When Two Energy Futures was first published in 1980, the nation had recently experienced the effects of the Iranian cut-off of oil, and memories of the embargo of 1973-74 had been sharply revived. We had learned the cost of over-reliance on imports and government price and allocation controls. And we had seen that individuals bear the ultimate burden of America's energy problems.

Since then, much progress has been made. And -- although much remains to be done -- it is clear that individual Americans are the beneficiaries of that progress.

Ending federal controls on crude oil prices was a major step in that progress. Increased energy conservation and energy production in the United States provided the opportunity for significant reductions in oil imports. The removal of federal controls on natural gas could help further this trend.

With reduced oil imports, the nation has had less fear of energy blackmail and more freedom to conduct foreign affairs. The dollar is stronger, oil prices are lower, and OPEC's control over oil markets has been weakened.

For individual Americans, these improvements in the nation's well-being have been important. Specifically, they have meant:

- More assured supplies of energy. Increased energy conservation and energy production and the resulting import reduction have made energy shortages less likely.

- Lower oil import bills. In 1981 and 1982 the United States imported less oil and paid a lower price for the oil that was imported. In fact, in 1981 U.S. consumers paid an estimated \$12.8 billion less for petroleum imports than they would have without decontrol of U.S. crude oil. This amounts to an average reduction in payments abroad of about \$150 per household. In 1982, the estimated savings were greater -- \$14.5 billion in total¹ and about \$175 per household² -- compared with what consumers would have paid under the previous system of government controls.

• Lower gasoline prices. After peaking in early 1981, both domestic and imported crude oil prices declined steadily for more than a year, some product prices leveled off, and the price of gasoline in the United States fell significantly. At the beginning of 1981, some observers had projected that decontrol of crude oil prices would cause gasoline prices to rise sharply over the remainder of the year. In fact, the price of gasoline in the fall of 1982 was actually less than it was when oil price controls were ended in January 1981. And, as 1983 began, gasoline prices had dropped still further. Although the downward trend in gasoline prices was interrupted in early 1983 -- largely because of the 5 cents per gallon increase in the federal excise tax that took effect on April 1 -- the results are clear: decontrol did not spark a sharp rise in gasoline prices but instead allowed market forces to lower prices.

• More goods and services. Energy is a resource consumers use directly in their homes and cars and indirectly in the production of goods and services that they buy. More efficient energy production and consumption because of decontrol allowed a greater supply of all goods and services to be produced. With more goods and services available, domestic prices and the rate of inflation were lower than otherwise. During 1980, the Consumer Price Index (CPI) -- a commonly used measure of the cost of living -- increased at an annual rate of 12.4 percent. But in 1981, the rate was 8.9 percent, in 1982 the rate was 3.9 percent, and several economists estimated that the rate in the first half of 1983 would be in the neighborhood of 3 percent. While many factors affect the rate of price increases, greater efficiency in energy markets has contributed to the improvement.

• A stronger dollar and lower prices for imported consumer goods. Reduced oil imports and a lower price for the oil imported have contributed to improvement in the balance of payments. Fewer dollars are shipped abroad to pay for oil. Each dollar is therefore more valuable and buys more goods abroad than it did before decontrol. As a result, foreign products -- from cameras to coffee to foreign vacations -- are less expensive for Americans.

These examples show that improvements in the nation's energy situation can result in real benefits for individual Americans. But such benefits are truly meaningful only if they can be sustained over the long term. As this fourth edition of Two Energy Futures concludes, much progress has been made toward a bright energy future -- but much remains to be done to assure that future. Discussions of progress must not lead to complacency. If the nation views recent progress as enough and chooses policies that do not encourage the efficient and wise development and use of its vast energy resources, that better energy future could slip from our grasp. As we look toward the future, Americans as individuals and the nation as a whole must continue to make choices that assure energy progress.

APPENDIX

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CHAPTER IX. ECONOMIC BENEFITS OF REDUCING IMPORTS

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CHAPTER X. ENERGY SECURITY -- INDIVIDUAL BENEFITS

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2. The numbers for U.S. households -- 80,376,609 in 1981 and 83,527,000 in 1982 -- are from the U.S. Bureau of Census, Population and Households by States and Counties: 1980, Supplementary Reports, 1980 Census of Population, Series PC80-S1-2 and U.S. Bureau of Census, Current Population Reports, P-20, Number 376.

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